AD-A173 688 FEASIBILITY STUDY OF COAL GASIFICATION/FUEL CELL/COGENERATION PROJECT FOR..(U) EBASCO SERVICES INC NEW YORK B ROSSI ET AL. NOV 85 DAAG29-85-C-0007 1/3

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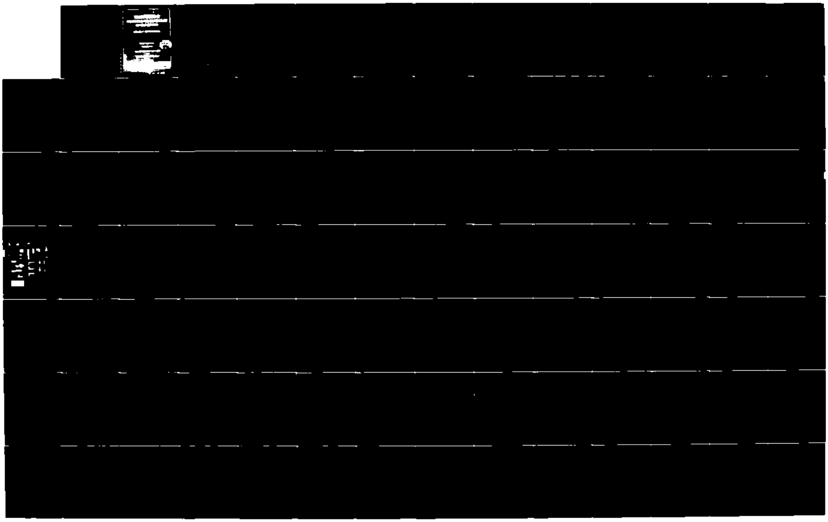

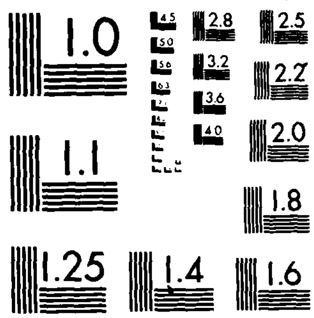

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FEASIBILITY STUDY OF

COAL GASIFICATION / FUEL CELL / COGENERATION

FORT GREELY, ALASKA SITE

PROJECT DESCRIPTION

REPORT CLIN 000304

PREPARED FOR

DEPARTMENT OF THE ARMY

AND

GEORGETOWN UNIVERSITY

NOVEMBER, 1985

EBASCO

EBASCO SERVICES INCORPORATED

Two World Trade Center,

New York, N.Y. 10048

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SECURITY CLASSIFICATION OF THIS PAGE (When Data Entered)

REPORT DOCUMENTATION PAGE

READ INSTRUCTIONS BEFORE COMPLETING FORM

1. REPORT NUMBER: CLIN 000304	2. GOVT ACCESSION NO.: AD-A173688
3. RECIPIENT'S CATALOG NUMBER	
4. TITLE (and Subtitle): FEASIBILITY STUDY OF COAL GASIFICATION/FUEL/CELL/ COGENERATION, FORT GREELY, ALASKA SITE PROJECT DESCRIPTION	5. TYPE OF REPORT & PERIOD COVERED: Site Specific Project Description
	6. PERFORMING ORG. REPORT NUMBER
7. AUTHOR(s): B Rossi, P Estreich	8. CONTRACT OR GRANT NUMBER(s): DAAG 29-85-C-0007
9. PERFORMING ORGANIZATION NAME AND ADDRESS: Ebasco Services Inc, 2 World Trade Center, New York, New York 10048	10. PROGRAM ELEMENT, PROJECT, TASK AREA & WORK UNIT NUMBERS: 611102-BH57-09
11. CONTROLLING OFFICE NAME AND ADDRESS: Procurement Office, U S Army Research Office, P O Box 12211, Research Triangle Park, N C 27709-2211	12. REPORT DATE: November, 1985
	13. NUMBER OF PAGES: 172
14. MONITORING AGENCY NAME & ADDRESS(if different from Controlling Office)	15. SECURITY CLASS. (of this report): Unclassified
	15a. DECLASSIFICATION/DOWNGRADING SCHEDULE

16. DISTRIBUTION STATEMENT (of this Report)

Approved for public release: distribution unlimited

17. DISTRIBUTION STATEMENT (of the abstract entered in Block 20, if different from Report)

18 SUPPLEMENTARY NOTES

Prepared in cooperation with Georgetown University. The views, opinions and/or findings contained in this report are those of the author(s) and should not be construed as an official Department of the Army position, policy or decision, unless so designated by other documentation.

19. KEY WORDS (Continue on reverse side if necessary and identify by block number)

Fuel Cell/Coal Gasification/Cogeneration/Exemplar Study

20. ABSTRACT (Continue on reverse side if necessary and identify by block number)

Report describes a Coal Gasification/Fuel Cell/Cogeneration (GFC) project that is specific to the Fort Greely, Alaska site.

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1.0 INTRODUCTION

The purpose of this report is to describe a Coal Gasification/Fuel Cell/Cogeneration (GFC) project that is specific to the Fort Greely site in Alaska.

The project at this site, as with those at the three other sites selected for this program, is intended to demonstrate the technical, economic and financing viability of power generation by fuel cells using gas from coal.

The specific design described in this report is based on a Westinghouse Corporation nominal 7.5 MW fuel cell with local sub-bituminous coal fed to the gasifier. This design evolved from the following two predecessor reports:

1. CLIN 0001 - Basic System Description, March 1985
2. CLIN 000204 - Preliminary Site Survey

Although this report does not include cost estimates or economic and financial analyses, it is intended to form the basis for such information which will be included in forthcoming reports numbered CLIN 0004, CLIN 0005 and CLIN 0006.

Mass and energy balances have been prepared for the gasification, gas processing, fuel cell and thermal management systems using the locally available design coal as a basis.

With safety, aesthetic and land use criteria satisfied, this plant will meet federal and local environmental laws and regulations, should have a design/fabrication/construction period of approximately 44 months and have performance characteristics as shown in Table 2-2.

1.1 Overview

Section 2.0 of this report discusses design criteria, describes the plant in general terms, discusses plant performance, plant availability and required staffing. It then addresses a project schedule that accounts for requirements additional to the basic GFC plant that integrate the total installation with the existing site's physical plant and unique energy needs. These additional requirements are referred to as the "GFC Site Specific Increment" and are described in this section.

Section 3.0 discusses the physical arrangement of the plant as well as the electrical and other utility connections.

Section 4.0 discusses present and future electrical loads and Section 5.0 covers the same for thermal loads.

Section 6.0 entitled, System Design Description, discusses for each of the major systems constituting the GFC, functions and design requirements, describes the system and discusses system performance, maintenance requirements and technical risks.

Section 7.0 discusses environmental regulations and permitting requirements, comparing GFC emissions with regulatory limits.

1.2 The following summarizes some of the information contained in this report.

1.2.1 General

- Plant floor area is approximately 57,000 ft^2, excluding external access roads;
- Plant is designed around a 7.5 MW Westinghouse fuel cell for study purposes, although this may not be the final design selection;
- The Thermal Management System (TMS) is arranged to maximize thermal output;
- Plant will meet PURPA criteria for a "Qualifying Facility" (QF).

- GFC emissions will be below regulatory limits;
- Electrical connection of power output to the Golden Valley Electric Authority (GVEA) grid will follow industry guidelines and include any additional GVEA and Fort Wainright requirements.

1.2.2 System Design Description

A. Material Handling

1. Coal

- The function of this system is to receive, weigh, sample, screen, store and convey coal to the gasifiers.

2. Ash

- The function of this system is to remove the ash that collects in each gasifier storage hopper.

The material handling system requiring only basic maintenance, has high reliability and low technical risk.

B. Coal Gasification

- The function of this system is to derive gas from coal for ultimate use by the fuel cell;
- Performance of the Wellman-Galusha gasifier indicates that it can operate from 8.5% to 111% of its rated capacity of 4 tons/hr. Note that this technology is used as a comparative baseline for all sites although it may not be the final design selection;
- Maintenance is minimal, most of it being performed during the scheduled two week annual shutdown;

- As a system with a long history of successful industrial application, technical risks are minimal.

C. Gas Processing

- The function of this section is to cool, clean, and compress the gasifier effluent, and then to convert it to a hydrogen-rich, sulfur-free stream, suitable for use by the fuel cell;
- Performance of this section is satisfactory under full and part load conditions, with variations in flow rate not adversely affecting gas quality;
- Equipment for this process is selected for maximum reliability and minimum maintenance. Major maintenance is performed during the scheduled annual shutdown;
- Constant/intermittent flare off will be mitigated by aesthetic design measures to meet local requirements;
- Technical risks are assessed as low.

D. Fuel Cell and Power Conditioner

1. Fuel Cell

- The function of the fuel cell is to convert hydrogen in the gas from the Gas Processing Section into usable electrical, mechanical, and thermal energy;

- The fuel cell operates at about 10% greater efficiency at 50% load than at 100% load. Voltage degrades a little more than 10% over the 40,000 hour life of the cell stacks;

- Maintenance for the expander, compressor and generator is typical of that for rotating equipment. Fuel cell stacks are periodically replaced to maintain minimum voltage level;

- Technical risks include the potential for electrolyte leakage, low cell voltage, catalyst poisoning or coolant fouling. However these problems can be averted through design changes or proper maintenance.

2. Power Conditioner

- The function of the power conditioner is to convert the dc output of the fuel cell to 3 phase ac power for connection to the GVEA grid. It also regulates operation of the fuel cell to maintain the required power output;

- Performance of the power conditioner is rated at an efficiency of 95% at rated design and above 90% for the entire operating load range;

- Systems utilizing similar design concepts (e.g. Tokyo Electric Power Co. (TEPCO) 4.5 MW cell) have proven to be reliable in utility related applications.

E. Thermal Management System (TMS)

- The TMS converts thermal and chemical energy flows discharged from the fuel cell into one or more of following energy forms that can reduce plant operating costs or generate revenue.

1) Steam and electrical power to satisfy GFC system process demands;
2) Steam to satisfy Fort Greely's main post heating requirements;
3) Electrical power for use by Fort Greely, Fort Wainright or for sale to GVEA.

- Since fuel cell efficiency increases as load decreases, steam production tends to drop more rapidly that does fuel cell power output with a lowering of load.

Equipment for the TMS is of proven reliability which can be sustained through regular maintenance.

Technical risk is minimal, being no more than that normally assumed by commercial ventures in mature technologies.

F. Auxiliary Systems

- Among the auxiliary systems are: 1) Electrical for powering auxiliary systems; 2) Glycol cooling system to dispose of heat from coal gasifiers, gas processing, and the TMS system; 3) Water treatment to condition water for process use; 4) A space heating and ventilation system for the GFC enclosures.

- The instrumentation and control system is configured with centralized control and control processors. Each major stage of the GFC process has a local subsystem control board located close to the process area.

G. Environmental

This section reviews generated emissions, discusses the applicable environmental laws and regulations and concludes that the GFC system requires no extraordinary emission control measures.

1.2.3 GFC Site Specific Increment

The "GFC Site Specific Increment" assures that the site receiving the fuel cell system has its unique energy requirements fulfilled with no net loss of prior essential assets or facilities.

At Fort Greely, the GFC Site Specific Increment includes the following:

1. Provision of coal use capability up to peak heating load for the Main Post. This entails providing additional gasifiers and compressing and feeding their raw gas output to one existing boiler such that the steam from this boiler plus steam from the GFC equals the Main Post steam demand. Based on a peak steam demand of 55,000 lb/hr and a GFC output of 13,800 lb/hr, the existing boiler upgraded to accept raw gas must produce 41,200 lb/hr of steam. Specifically this site specific requirement consists of the following:

    a. Two 8 ft diameter gasifiers each consuming 4500 lb/hr of coal and producing approximately 23,700 lb/hr of raw gas at atmospheric pressure. Each gasifier is equipped with a centrifugal blower to pressurize and convey the raw gas.

    b. An 18 inch aboveground pipeline and connections to convey the 480F raw gas from the gasifiers to the existing reworked boiler. Pipeline is complete with foundations, supports, expansion provisions, fittings and valves. The pipeline is also insulated with 3 inches mineral wool or equivalent, preventing condensation of the tar vapors.

    c. Reworking of one of the three existing oil fired boilers to accept raw gas from the two gasifiers in (a) above.

    This may include in addition to burners and controls, soot blowers and increased induced draft fan capacity and ducting due to to the higher volumetric flow of combustion products.

    Because of lower flame temperatures with use of the low Btu gas, reduced furnace heat absorption may be expected to cause boiler derating.

    d) Additional coal handling and storage capacity to serve the gasifiers in item (a) above.

2. Steam and condensate connection from the GFC plant to the existing heating system mains.

3. Steam and condensate connection from the existing oil fired boilers to the GFC plant heating to be used during shutdown of GFC plant. Common use of steam and condensate lines in Item 2 should be considered.

2.0 SUMMARY

2.1 Design Criteria

Criteria and design objectives that govern the design and selection of systems, equipment and supporting facilities for the GFC plant are as follows:

1. Plant Availability and Reliability

   a) Maximum plant availability is to be achieved through use where possible, of commercially proven equipment.

   b) Redundancy is to be provided for critical controls and for selected motorized equipment.

   c) Coal storage is to provide a minimum of 120 days GFC operation at plant maximum continuous rating during the coldest four months of the year.

2. Plant is designed around the Westinghouse 7.5 MW nominal output fuel cell.

3. Plant is to operate baseloaded with the Thermal Management System designed to maximize steam export rather than electrical power generation.

4. System operation is to be based on maximum automation and centralized control.

5. Plant is to be capable of meeting federal and local environmental requirements.

6. Most plant components are to be factory fabricated and pressembled for truck delivery.

7. Access roads for coal delivery, ash removal and for other vehicles serving the facility, must not interfere with main post traffic flow.

8. Safety criteria and regulations must be complied with, including those governing hydrogen, carbon monoxide and sulfuric acid.

9. Plant must provide suitable access for fire brigade vehicles and personnel.

10. Plant must meet Public Utilities Regulatory Policies Act (PURPA) criteria for classification as a "Qualifying Facility" (QF).

11. Visual effect of intermittent gasifier flares and ammonia stripper flare shall be mitigated by aesthetic design to meet local requirements.

12. Plant site conditions are as summarized in Table 2-1.

TABLE 2-1

SITE CONDITIONS[1]

Elevation Above Mean Sea Level, ft	1314
Design Atmospheric Pressure, psia	14.03
Summer Outdoor Design Temperatures, °F[2]	
(Dry Bulb)/(Mean Coincident Wet Bulb)	80/61
Winter Outdoor Design Dry Bulb, °F[3]	(-48)
Summer Indoor[5] Design Dry Bulb, °F	105
Winter Indoor[5] Design Dry Bulb, °F	55
Annual Heating Degree Days, Average[4]	13698

Notes:

1. Technical Manual TM-5-785, Engineering Weather Data, July 1, 1978, Department of the Army, p. 1-3, Data for Fort Greely.

2. Dry bulb equaled or exceeded 1% of time on the average during the warmest four consecutive months.

3. Dry bulb equaled exceeded 99% of time on the average for the coldest three months.

4. 30 year average for 65°F base.

5. Unairconditioned spaces.

2.2 Overall Plant Description

Layouts indicate that excluding coal storage, approximately 57,000 ft^2 of area is required for the GFC system. (Refer to paragraph 3.1). The tallest structure is the Wellman-Galusha gasifier. Including the feed conveyor, the gasifier is 80'-0" above the base slab.

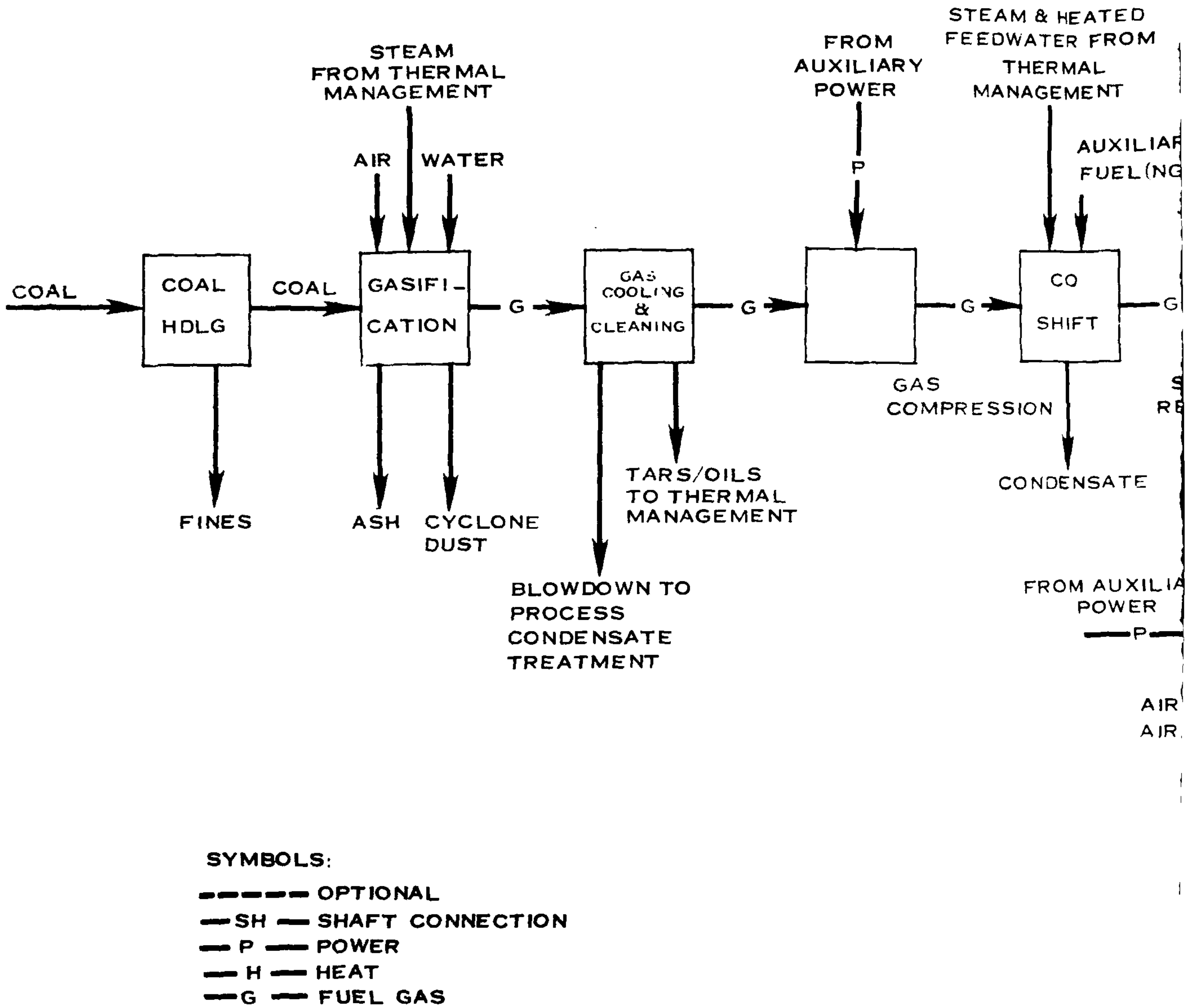
This system is based on the Westinghouse fuel cell and has a nominal gross electrical output of 7.5 MW.

A conceptual view of the base system design is given by the block flow diagram of Figure 2-1. Coal delivered by truck is placed either in the live storage day silo or in the emergency 120 day open storage pile. Coal is normally reclaimed from the silo and conveyed to the two Wellman-Galusha gasifiers. Saturated gasification air reacts with the coal in the gasifier, producing hot raw gas and ash. The raw gas is compressed to 117 psia by a three stage centrifugal gas compressor which is driven by a motor that is electrically powered from GFC system output and helper turbine.

Utilizing steam at 120 psia from the CO Shift boiler and from the Thermal Management System, the compressed gas undergoes a CO shift reaction to increase the hydrogen content. The gas is then desulfurized and heated before final polishing and feeding to the fuel cell.

Receiving compressed fuel gas and air at the anode and cathode respectively, the fuel cell electrochemically converts the energy in the hydrogen and oxygen components of these feed gases to direct current power and heat. The fuel cell power output is then conditioned for use in an AC utility network.

Vent gases from the fuel cell are oxidized in a catalytic combustor and then passed through a turbo expander which drives a 2780 kW generator. Exhaust from the expander goes to a heat recovery steam generator (HRSG) which includes a supplementary burner section to fire the tars and oils produced by the gasifier. A part of the steam generated by the HRSG provides 120 psia steam for gas processing. The remaining 13,800 lb/hr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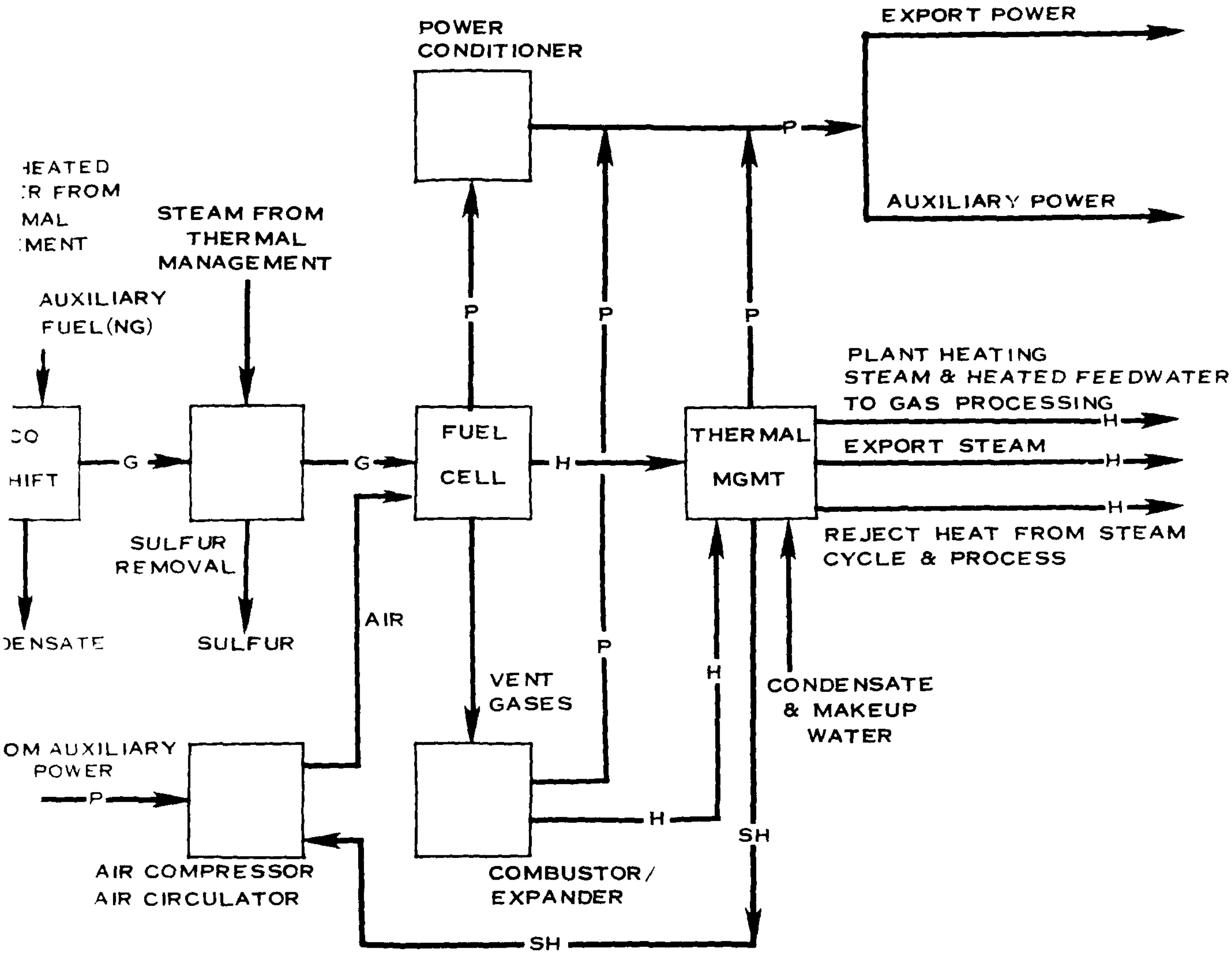

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FORT GREELY, ALASKA SITE

BLOCK FLOW DIAGRAM

FIGURE 2-1

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of steam is available for use in the Main Post steam distribution system for space/domestic hot water heating.

The HRSG exiting gas is cooled, condensing water vapor for reuse in the process.

A second HRSG extracts heat from the fuel cell cooling air, using it to preheat feedwater and to generate steam at 50 psia for use in the helper steam turbine gasifier, ammonia stripper and for GFC plant heating.

These HRSG's are part of the Thermal Management System which receives and "manages" heat from the fuel cell electrochemical reaction, from the combustor/expander and from any process heat source. Design of the Thermal Management System influences the magnitude and relative proportions of plant power output and export heat.

Most of the heat received by the Thermal Management System is directed to the Gas Processing Section for use in the CO Shift and to the helper steam turbine that drives the cathode air compressor and fuel cell air circulator.

Also included in the Thermal Management System is a dry cooling tower and circulating glycol system that removes approximately 30 x 10^6 Btu/hr of heat rejected from the gas process, from compressor intercoolers and from the steam condensers serving the helper turbine.

Other systems required to support the facility include fire and gas leak detection and protection, instrumentation and controls, makeup water treatment, drainage, heating and ventilation of enclosures, freeze protection of equipment and piping, flush water, compressed air, nitrogen for blanketing and purging and hydrogen for startup and fuel cell passivation.

2.3 Plant Performance

GFC plant performance is summarized in Table 2-2. The plant has an overall efficiency of 28.9% and a heat rate of 18,000 Btu/kWh.

If a UTC fuel cell is substituted for the base case, the efficiency rises to 38.9% and the heat rate reduces to 12,600 Btu/kWh. In both cases the HRSG is downstream of the gas expander and the tars and oils are fired in an HRSG supplementary burner.

A portion of the resulting steam output satisfies heating requirements of Fort Greely which vary throughout the year. Excess steam not used for heating is supplied to the helper turbine. The recommended scheme for any future work at this site depends upon results of the subsequent economic (CLIN 0004) and financial (CLIN 0005) assessments.

The Public Utilities Regulatory Policies Act (PURPA) which is administered by the Federal Energy Regulatory Commission (FERC), provides criteria for a cogeneration facility becoming a Qualifying Facility (QF).

An important advantage of this QF status is that it mandates purchase at avoided costs by the public utility of electric power produced by the cogenerator.

The operating standard of PURPA requires that a new QF must produce at least 5% of the total energy output as useful thermal energy. The facility heat balance in Section 6.5 satisfies this requirement with a thermal energy percentage of 44.

The second standard imposes criteria for minimum operating efficiencies on facilities where oil or gas is the primary fuel and is therefore not applicable to this system.

The remaining requirement states that a utility may not own more than 50% of a cogeneration facility and is also inapplicable.

TABLE 2-2

SYSTEM PERFORMANCE

		$W^{(1)}$
a.	Coal Delivered to Plant, Tons/D	199.0
b.	Excess Coal Fines$^{(2)}$, Tons/D	23.4
c.	Coal Input to Gasifier$^{(3)}$, Tons/D	175.6
d.	Heating Value of Coal Input$^{(4)}$, Btu/hr	109.9×10^{6}
e.	Fuel Cell Output, MW DC	7.5
f.	Power Conditioner Output, MW AC	7.1
g.	Power from Gas Expander, MW	2.8
h.	Power from Steam Turbine, MW	-
i.	Auxiliary Power, MW	4.8
j.	Net Power, MW	5.1
k.	Export Steam @120 psia, lb/hr	13,776
l.	Tar and Oils Heat Content, Btu/hr x 10^{-6}	15.7
m.	Heat Rate, Btu/KWh$^{(5)}$	18,800
n.	Overall Plant Efficiency, % (5)	28.9

Notes:

1. Westinghouse (base design) and sub-bituminous coal.
2. Coal fines in excess of 15%. It is assumed that these fines which are in excess of 15% will be trucked to Fort Wainright for use in their boilers. If Fort Wainright cannot accept these fines, they may be fired in future coal boilers at Fort Greely.
3. Based on gasifier accepting 15% fines and coal received with 25% fines.
4. Based on higher heating value of 7,510 Btu/lb.
5. Definitions:

   Heat Rate = ((d)-(k)H)/(1000 j)

   Overall Plant efficiency = $(3.412\times10^{6}(j)+(k)H)/(d)$

   where H = export steam/condensate enthalpy difference

Based on the above, the performance of the GFC system at Fort Greely meets the criteria for classification as a "Qualifying Facility."

The overall energy balance is shown in Table 2-3.

As received coal is expected to have approximately 25% fines[3].

Based on the ability of the gasifier to accept up to 15 percent fines, 47% of incoming fines (23.4 T/d) are screened and stored until possible sale or transport to Fort Wainright for use in their heating/power plant. Excess fines from the GFC can also be burned in any future coal fired boilers installed at Fort Greely.

Of the total system energy loss of 78 x 10^6 Btu/hr, 80 percent occurs in the coal handling, coal gasification and gas processing sections of the GFC system.

Therefore, in the final design of this system, major efforts must be directed to reducing these losses in order to maximize cycle efficiency.

TABLE 2-3

OVERALL ENERGY BALANCE (BASE CASE)

Item		Energy (10^6 Btu/hr) In	Out
Energy in Coal Delivered to Plant		124.60	
Energy Produced (Gross)			33.79
Fuel Cells	24.23		
Gas Expander Generator	9.56		
Parasitic Power			(16.38)
Export Steam			14.38
Energy in Byproducts			17.01
Excess Coal Fines	14.60		
Cyclone Carbon Dust	1.93		
Ash	.48		
Heat Rejected by Cooling Tower			30.00
Other Heat Releases to Environment			45.80
CO Shift Air Cooler	9.90		
HRSG Stack Loss	19.50		
Miscellaneous	16.40		
TOTAL		124.60	124.60

2.4 Plant Availability

Systems and equipment are to be selected and arranged to provide maximum overall availability and reliability.

Availability for one year operation is defined as

$$A = 1 - \frac{US + PS}{365}$$

and reliability as

$$R = 1 - \frac{US}{365 - PS}$$

where US = Unscheduled Shutdown, days/yr

PS = Planned Shutdown, days/yr

Estimates of the days per year of unscheduled shutdown were developed for the component sections of the GFC and listed in Table 2-4. The fuel cell, power conditioner and Thermal Management System estimate of 22 days unscheduled shutdown per year is based on Reference 2-1. (Within this system group, the power conditioner has a reliability of 98.2 percent which represents 6 days unplanned outage).

It may be noted that the Gasification, and Gas Processing Sections contribute an additional 14 days of unplanned shutdown, reducing the plant availability factor from 0.90 for a natural gas fueled plant to 0.86 for a coal gas fueled plant.

Operating as a base loaded plant at an average of 95 percent of maximum continuous rating, the plant capacity factor is 0.82 (= 0.95 x 0.86).

The above estimates apply to a GFC plant only after a sufficient period of "running in" and testing has occurred to eliminate initial operating and design problems. It is estimated that this period could be a year in duration.

Although the above estimates were made by reference to available experience with specific system components, plant availability will finally depend on the quality of operating and supervisory personnel and on the specific equipment and systems that are designed specified and installed. Also plant availability will have maximum sensitivity to equipment that is in some stage of development (e.g. the fuel cell, the PACT process and specific catalysts).

TABLE 2-4

PLANT AVAILABILITY

Unscheduled Shutdown[1]		Days/Yr
Fuel Cell, Power Conditioner, Thermal Management System[2]		22
Gasifier		3
Waste Heat Boiler		1
CO Shift		1
Stretford Desulfurizer		3
Gas Compressors		3
Material Handling[3]		3
Subtotal		36
Scheduled Shutdown		14
Total Annual Shutdown		50
Plant Reliability	(1 - 36/(365-14))	0.90
Plant Availability	(1 - (36 + 14)/365)	0.86
Plant Load Factor		0.95
Plant Capacity Factor	(0.86 x 0.95)	0.82

Notes:

1. Refers to complete GFC system shutdown caused by listed item.
2. See Reference 2-1
3. See Reference 2-2

2.5 Plant Staffing

An estimate of operator assignments to the various sections of the GFC plant for each of the three working shifts, is given in Table 2-5.

With each letter (A, B, C, etc.) representing one individual, five operators would be on duty at all times.

In addition to the five operators a supervisor would be located in the Control Room.

Considering days off, relief fill in, vacations, training, performance of maintenance tasks and premium payments for weekends and night shifts, a factor of 4.2 is applied to obtain "equivalent operating staff".

The total assigned to the plant is then as follows:

Equivalent Operating Staff (6x4.2)	25
Laboratory Technicians	3
Maintenance/Repair Personnel	3
Plant Manager/Engineer	1
Clerical	2
Total Equivalent Staff	34

TABLE 2-5

PLANT OPERATOR ASSIGNMENTS[1]

	Operator[2]
Material Handling	A
Gasification	A
Gas Cleaning, Cooling, Compression	B
CO Shift	B
Sulfur Removal & Recovery	B
Process Condensate Treatement	C
Water Treatment	C
Fuel Cell	D
Power Conditioner	D
Thermal Management System	D
Instrumentation and Control Systems	E
Auxiliary Systems	E

Total Operators = (A+B+C+D+E) =	5
Supervisor	1
Total Operating Staff	6

Notes:

1. Assignments are for a single shift.
2. Each letter (A, B, C, etc.) represents one plant operator.

2.6 Project Schedule

The 44-month project schedule shown in Figure 2-2 assumes that compliance with the National Environmental Policy Act (NEPA) will entail the preparation and review of an Environmental Assessment (EA) and not an Environmental Impact Statement (EIS). (If an EIS is required, the NEPA process could take an additional six months or longer.)

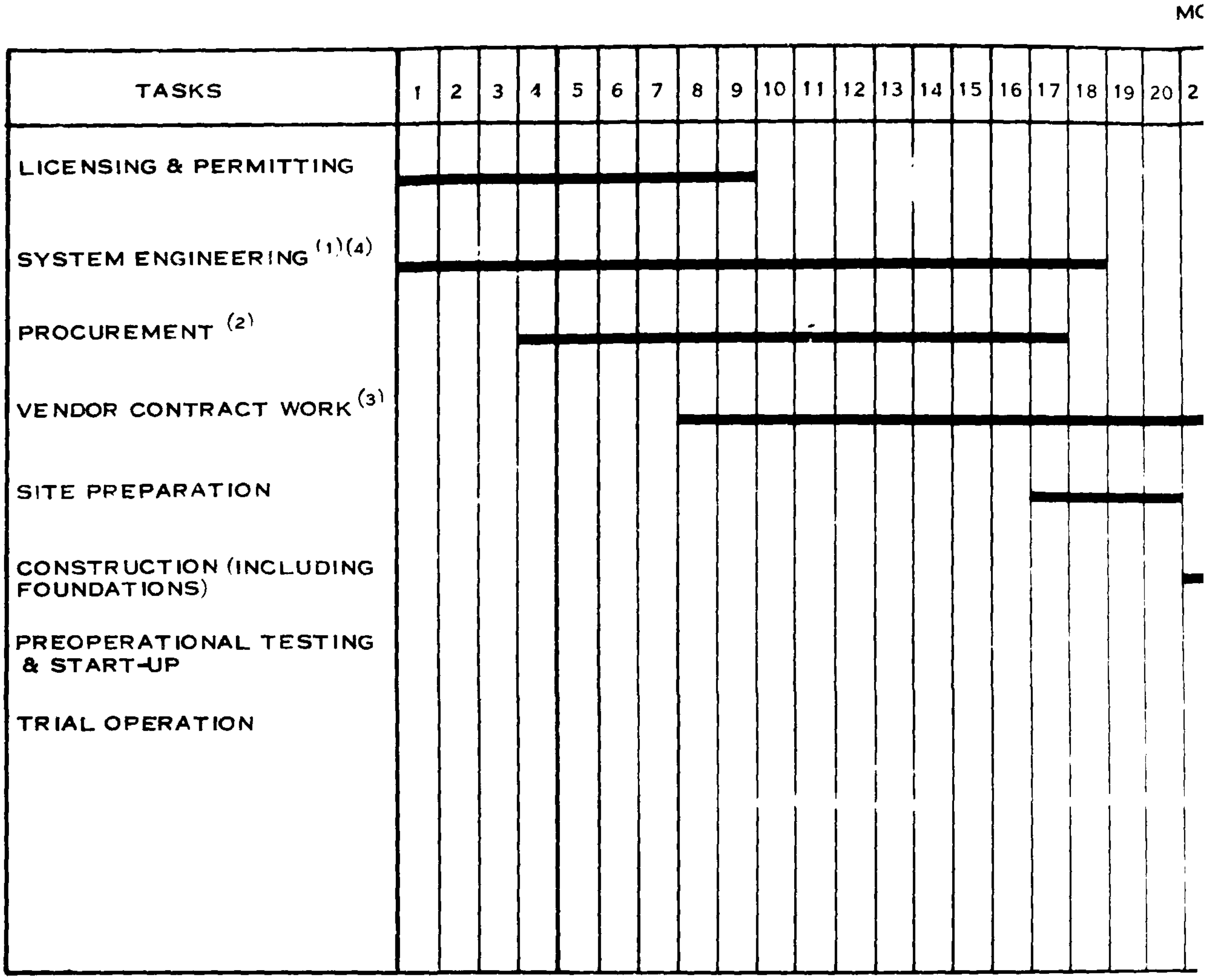
It also assumes that the federal and Alaska approvals and permits will be available seven months after project start. This in turn allows letting contracts for supply of the longest lead items.

Work on the GFC system foundations and structures would commence on the 21st month with installation of delivered equipment and interconnecting services completed in the 40th month.

It is estimated that site delivery would occur roughly 24 months after placement of an order in 1986 or 1987 - depending also upon prior production commitments. This makes the fuel cell/power conditioner package the project's longest lead item.

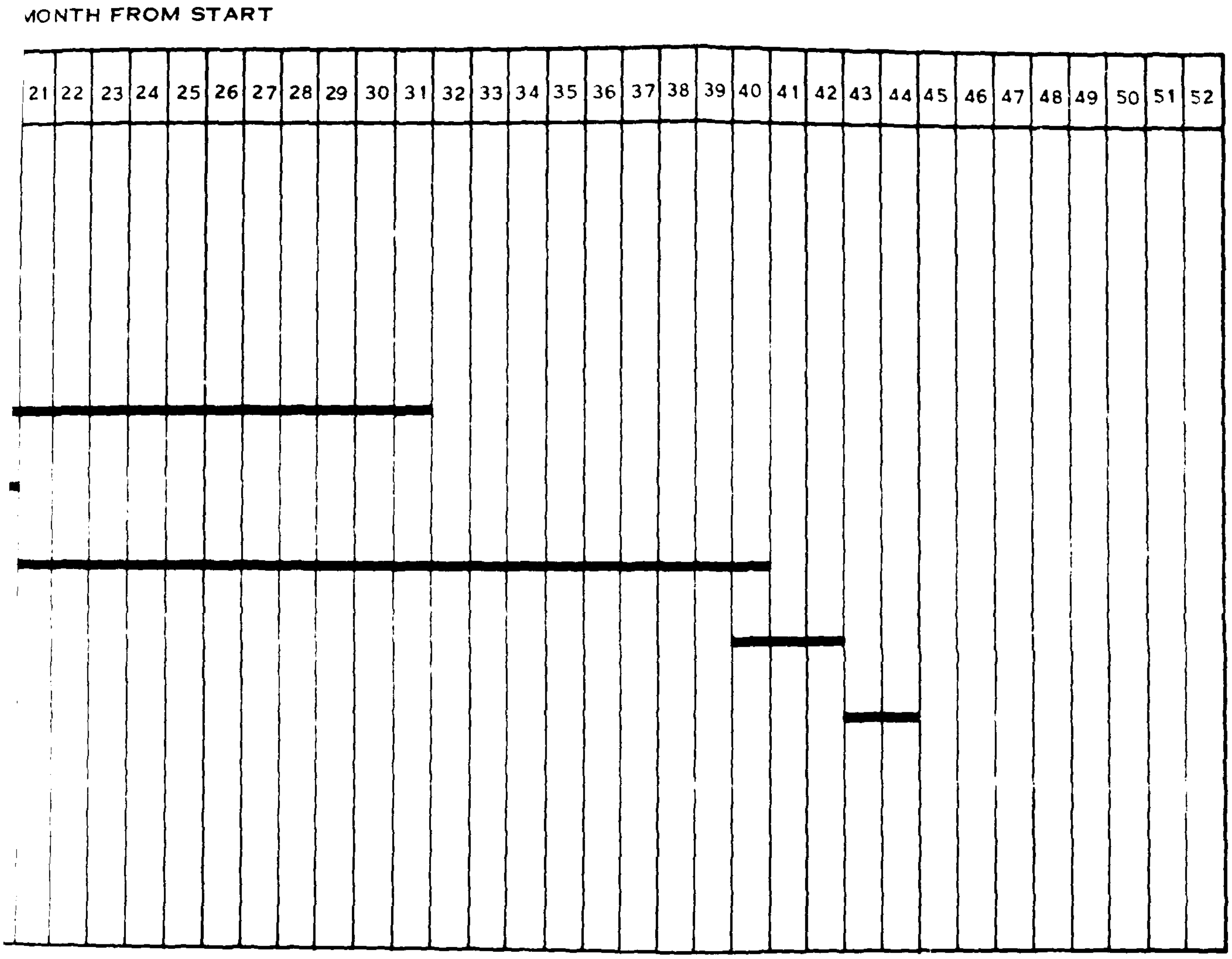
It therefore becomes necessary to initiate negotiations and place an order for the fuel cells as early in the project as possible. It is estimated that this order or letter of intent can be issued atout seven months after start of GFC engineering (11 months after project start) with delivery of the fuel cells occurring in the 35th month. Some typical "order to delivery" time frame estimates by other suppliers are:

Steam turbine-generator	-	40 weeks
Gas expander - compressor	-	54 weeks
Vessels and towers	-	45 weeks
Gasifiers	-	26 weeks



NOTES:

1. INCLUDES DEVELOPMENT OF SYSTEM DESIGN DRAWINGS, SPECIFICATIONS, BID ANALYSES, REVIEW OF VENDOR SUBMITTALS
2. INCLUDES PROCUREMENT ACTIVITIES UP TO CONTRACT AWARDS
3. INCLUDES VENDOR ENGINEERING, FABRICATION & DELIVERY
4. THE START OF ENGINEERING FOLLOWS A 9 TO 12 MONTH PERIOD FOR PRELIMINARY ENGINEERING AND COAL SAMPLE TESTING.



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COAL GAS/FUEL CELL/COGENERATION

FORT GREELY, ALASKA SITE

PROJECT SCHEDULE

FIGURE 2-2

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The fuel cell "order to delivery" time exceeding all those listed above, has the greatest influence on project duration.

The start of engineering in the first month follows a 9 to 12 month period for preliminary engineering, the final selection of a gasifier technology and sufficient progress in coal testing to confirm both the raw gas composition and the selection of a design coal. This preliminary phase of work is currently scheduled to start in early 1986 and to be completed by the end of that year.

2.7 Environmental

A comparison of GFC plant emissions and the applicable regulatory limits is given in Table 7-1 of Section 7.0.

This table shows air and liquid emissions to be well below regulatory limits. Solid wastes will be disposed of according to requirements of the Resource Conservation and Recovery Act and local laws. Noise will be controlled to meet both state and local requirements during construction and during operation.

2.8 References

2-1 Westinghouse Electric Corp., "Phosphoric Acid Fuel Cell, 7.5 MWe dc Electric Power Plant Conceptual Design," WAESD TR-83-1002, May 1983.

2-2 Fluor Power Services, Inc., "Component Failure and Repair Data for Coal-Fired Power Units", EPRI AP-2071, October 1981.

2-3 Personal communication on 3/29/85 with J. Usibelli, Jr. of Usibelli Mine Co.

3.0 PLANT GENERAL ARRANGEMENT

3.1 Configuration

The Coal Gasification/Fuel Cell/Cogeneration (GFC) plant is located approximately 500 feet north of existing Heating Plant 606 and east of the oil storage tanks.

Figure 3-1 shows the GFC Plant area. Figure 3-2 shows the equipment layout.

The GFC plant being studied includes one complete nominal 7.5 MW module. The module consists of the Coal and Ash Handling Section, Gasification Section, Gas Cooling, Cleaning and Compression Section, CO Shift Section, Sulfur Removal and Recovery Section, Process Condensate Treatment Section and the Fuel Cell and Thermal Management Section and Auxiliary Systems.

In addition the following facilities are included:

Administration and Control Building
Repair Shop
Parts Storage
Material Storage
Lockers

The plant is located at grade level in a fenced area of approximately 150' x 390' and is enclosed in heated and ventilated buildings approximately forty feet high. Because of their height, gasifiers are separately enclosed.

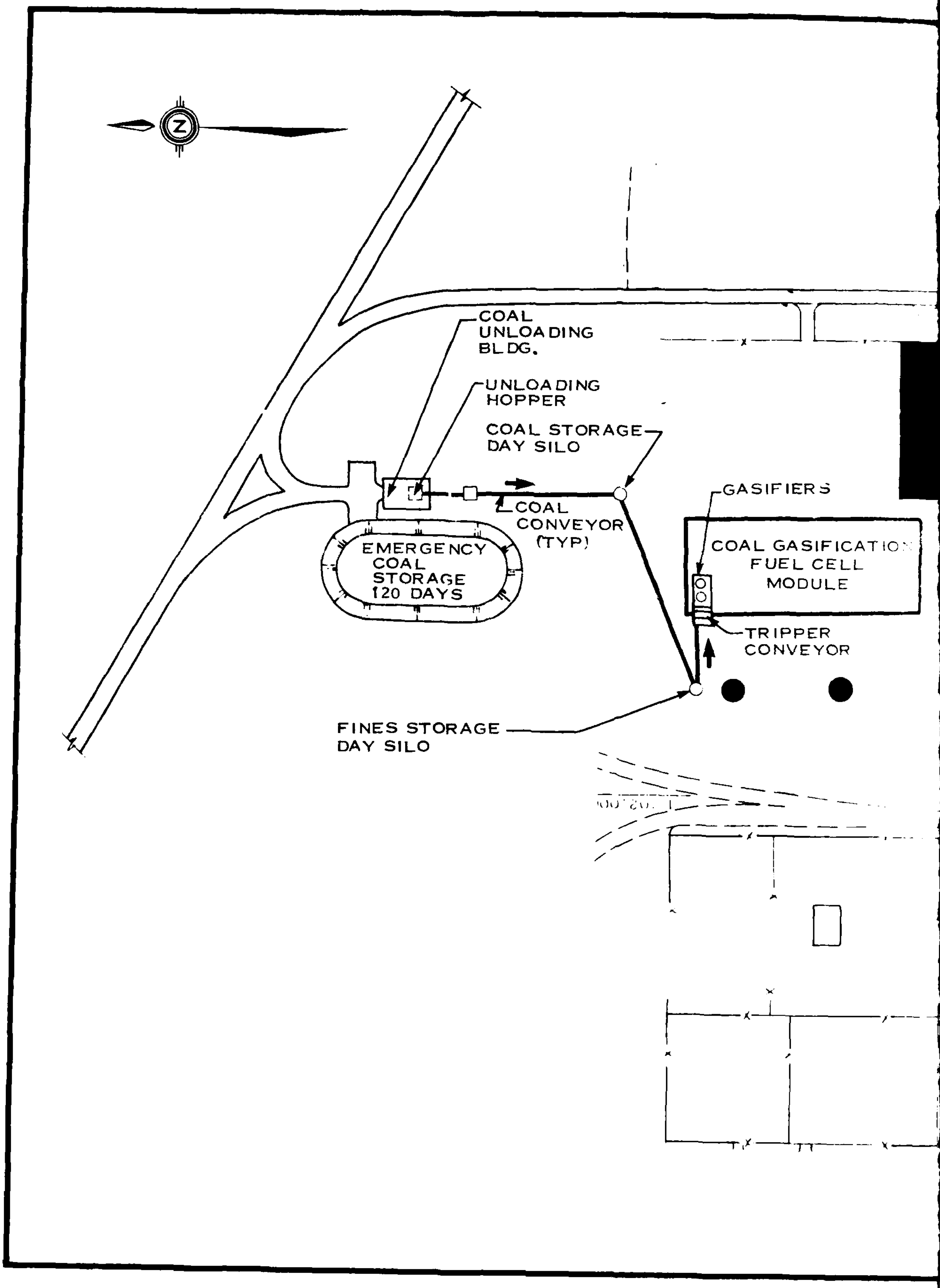
Buildings housing equipment or piping with pressurized gas have explosion vents in roof and in wall areas as prescribed by code or industry standards.

Coal is shipped from the mine by rail and transferred to trucks either at Ft Wainright or Eilson AFB.

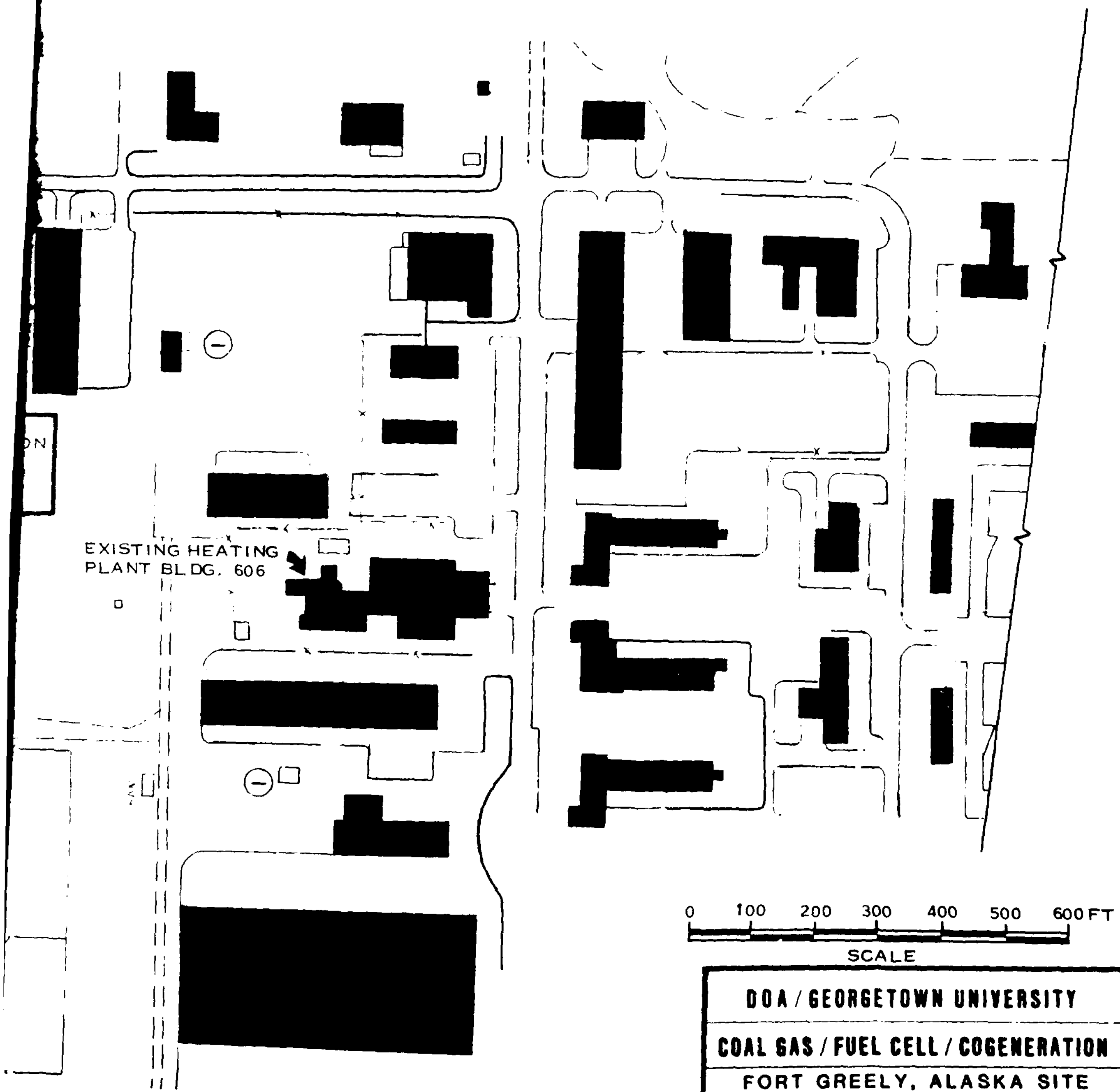
Upon delivery to the site by trucks, coal is stored in a day silo or in the 120 day emergency storage pile.

The contents of the gasifier ash hoppers and gasifier cyclone hoppers are unloaded directly into a truck on a daily basis for off-site dumping.

All equipment is fully accessible from the ground or from platforms and arranged with adequate space for operation, maintenance and repairs. Adequate laydown space and lifting devices are provided for equipment overhaul.



Z
COAL
UNLOADING
BLDG.
UNLOADING
HOPPER
COAL STORAGE
DAY SILO
GASIFIERS
COAL
CONVEYOR
(TYP)
EMERGENCY
COAL
STORAGE
120 DAYS
COAL GASIFICATION
FUEL CELL
MODULE
TRIPPER
CONVEYOR
FINES STORAGE
DAY SILO



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FORT GREELY, ALASKA SITE

PLOT PLAN

FIGURE 3-1

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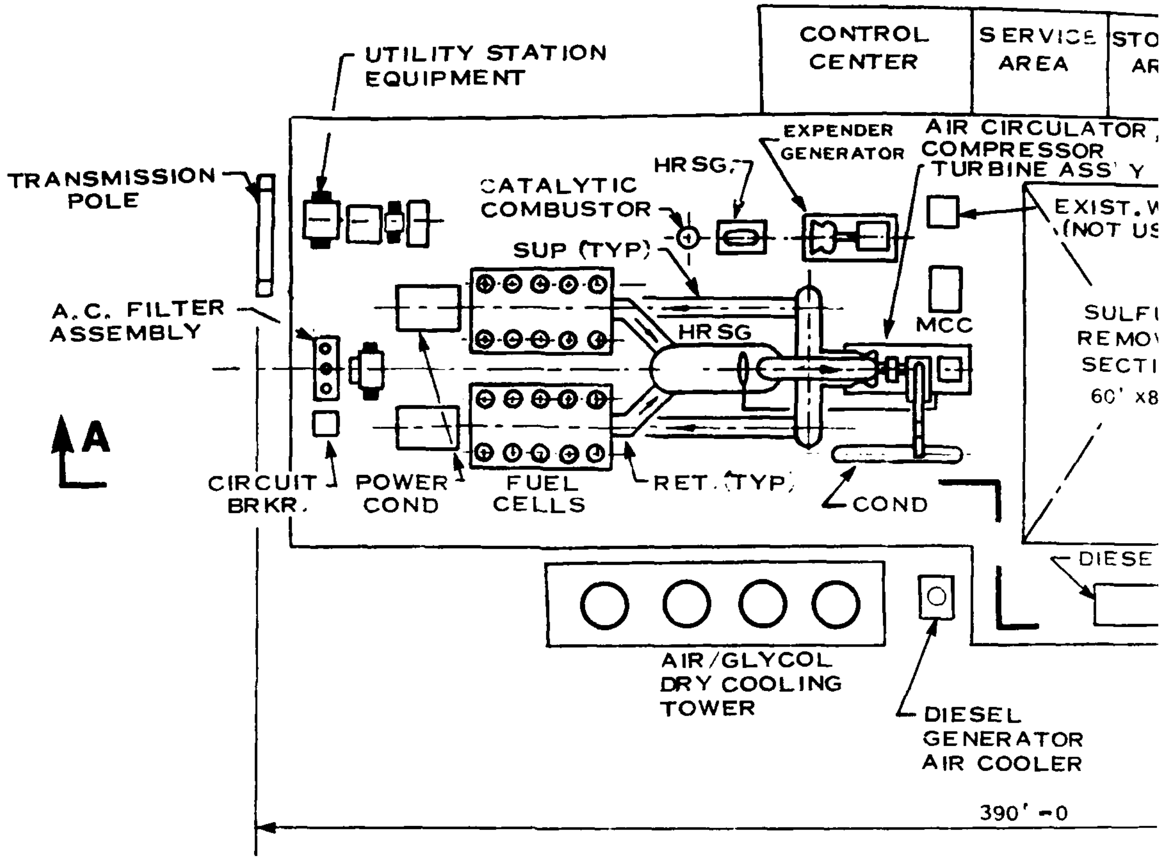
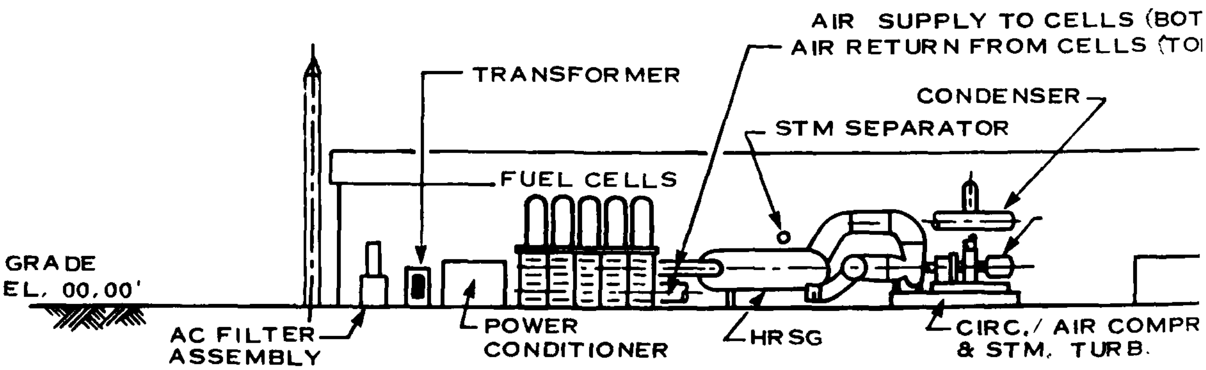
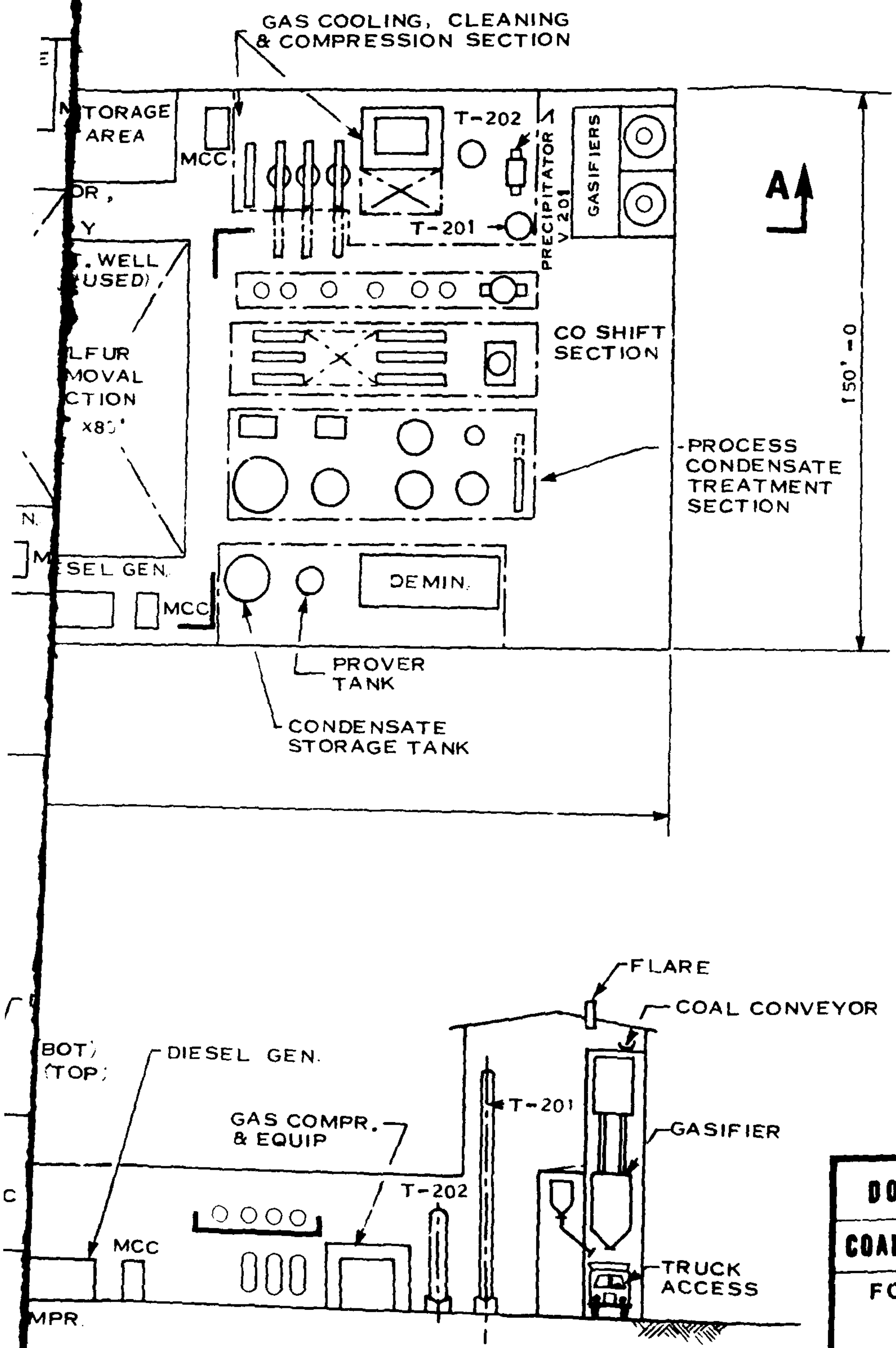


PLAN



SECTION A-A



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COAL GAS / FUEL CELL / COGENERATION

FORT GREELY, ALASKA SITE

GENERAL ARRANGEMENT

SCALE: 1"=40'

FIGURE 3-2

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Approach roads and aisles are designed for equipment removal and replacement by trucks and for access by the fire brigade.

A Control Center for the GFC is located adjacent to the service and storage areas and directly opposite the fuel cells.

3.2 System Interfaces

3.2.1 Electrical

Electrical connection of the GFC system to the Golden Valley Electric Authority (GVEA) grid including protective relaying, generally follows industry guidelines[1] and includes any additional GVEA requirements.

The fuel cell output is connected to the GVEA system through a static converter which is similar in all respects to those used throughout the power industry for HVDC and variable frequency systems, except that it must be designed to accept the input voltage variations associated with the fuel cell plant.

Statistics[2] indicate that availability of HVDC converters averaged 94.6 percent (98.2 percent if maintenance outages are excluded) for the period 1977-1981. The converter is of a 12-pulse design, with filters as required to reduce the harmonic content of power output to the GVEA system. Harmonic content of the converter output must conform to the requirements of Reference 3. Power components of the converter are conservatively rated to ensure maximum reliability. The converter is completely self protecting against faults and all thyristors are protected against current and voltage surges.

In general, the converter is of modular design for ease of maintenance. Cooling is accomplished by air or water, with two full capacity cooling systems being supplied.

In addition to the fuel cell output, power to the GVEA grid is also available from the expander-generator receiving fuel cell vent gases as they exit the catalytic combustor.

3.2.2 Other Site Utilities

All utilities to the GFC plant are metered for purposes of accounting and performance analysis.

a - Water

Fresh water supply is required for the gasifiers, the sulfur removal system and the Thermal Management System makeup as follows:

	Flow (gpm)
Gasifiers	5
Sulfur Removal System	1
Thermal Management Systems	7
Total	13

Water will be supplied from the existing water wells.

b - Fuel Oil

Arctic diesel oil No. 2 (135 gph per gasifier) is required for startup heater (F-301) in the CO shift section. Additionally, 10 gph of oil are required to support the ammonia flare.

c - Electric Power

Electric power for the GFC plant auxiliaries (pumps, compressors, fans, lighting, etc.) is supplied by the GFC system. Power from the existing Fort Greely diesel generators or from the Fort Wainright power plant is available for GFC plant startup.

d - Sewage

Effluent from the plant is treated to levels that meet local pretreatment requirements before discharge into the existing sanitary sewer line.

3.3 CIVIL

The Ft. Greeley site is located south of the zone of continuous permafrost. Thus, while the site may be underlain by permafrost extending to about eleven feet, the upper several feet of this frozen soil seasonally freezes and thaws. Foundations must therefore be designed to accommodate the effects of resulting seasonal heaving and settlement of these supporting soils. One typical solution involves structurally supporting all slabs and foundation components at a level which will remain permanently frozen (ie: using structural slabs supported on piles or caissons, in lieu of using slabs on grade and shallow footings). Another typical approach is to support proposed structures entirely upon an insulating layer (ie: several feet of gravel) which prevents the underlying insitu soils from thawing due to transmission of heat from the enclosed structure.

The determination of the optimal approach for foundation support depends on the configuration and loadings of the proposed structures, and the specific environmental and geotechnical properties of the site. The latter must be determined by comprehensive site subsurface investigation and analysis of laboratory tests of the site soils.

3.4 References

3-1 ANSI/IEEE C37.95-1973, Guide for Protective Relaying of Utility-Consumer Interconnections

3-2 Ebasco Report PRC-HVDC-001, High Voltage Direct Current (HVDC) Reliability Study, dated February 13, 1984.

3-3 IEEE 519-1981, Guide for Harmonic Control and Reactive Compensation of Static Power Converters.

4.0 ELECTRICAL LOADS

4.1 Present Load

Currently, load at Fort Greely is supplied from two sources. The first and primary source is the Fort Wainright power plant which wheeled approximately 14,629,000 kWh in 1984 over the GVEA transmission lines. The second source is the Fort Greely diesel-generator plant which supplied about 1,056,000 kWh in 1984 for the purpose of demand limiting. The average monthly electrical energy consumption is then approximately 1,307,000 kWh.

4.2 Future Load

Future electrical load is expected to remain essentially constant.

5.0 THERMAL LOADS

5.1 Present Load

An analysis of Heating Plant H-606 monthly fuel oil consumption shows that in the years, 1979 and 1984 oil was consumed for space heating at the average rate of 88.3 gallons per degree day with an additional constant monthly consumption for domestic hot water heating (July and August data) of about 93,000 gallons.

Peak steam load of the Main Post at (-48°F) outdoor temperature is 55,000 lb/hr and exceeds the export steam capability of the GFC by approximately 41,000 lb/hr. Refer to Table 6.5-1 for a tabulation of average monthly steam flows.

5.2 Future Load

Thermal load is not expected to increase over current requirements.

6.0 SYSTEM DESIGN DESCRIPTION

6.1 Material Handling

6.1.1 Coal Handling

6.1.1.1 Function and Design Requirements

The function of the coal handling system is to receive, weigh, sample, screen, store, meter and distribute coal to the gasifiers. Daily coal demand for the two gasifiers is 199 Tons/day.

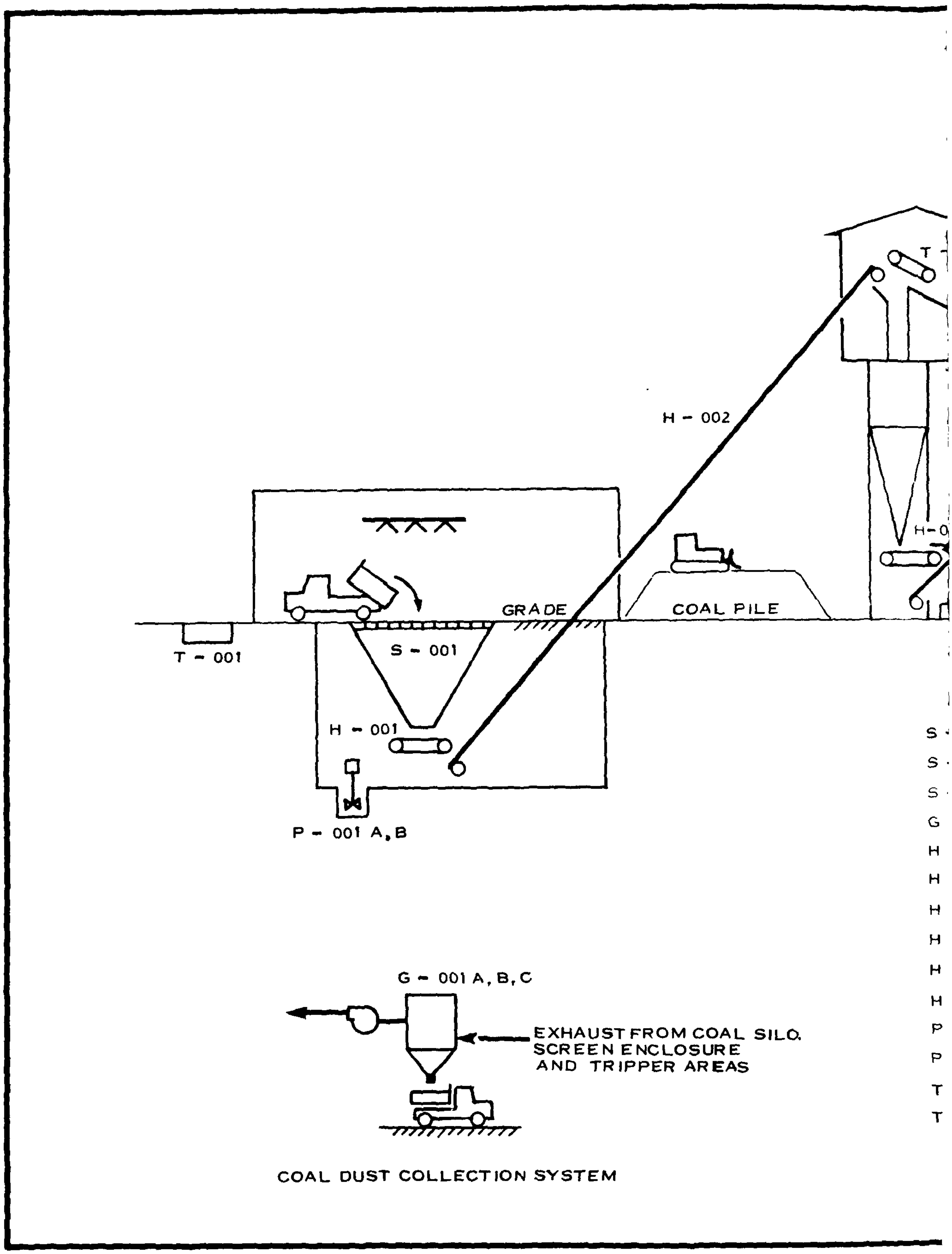
Storage facilities include a day silo of 200 tons capacity and an emergency 120 day open storage pile which allows continued operation during an extended interruption in coal deliveries.

6.1.1.2 System Description

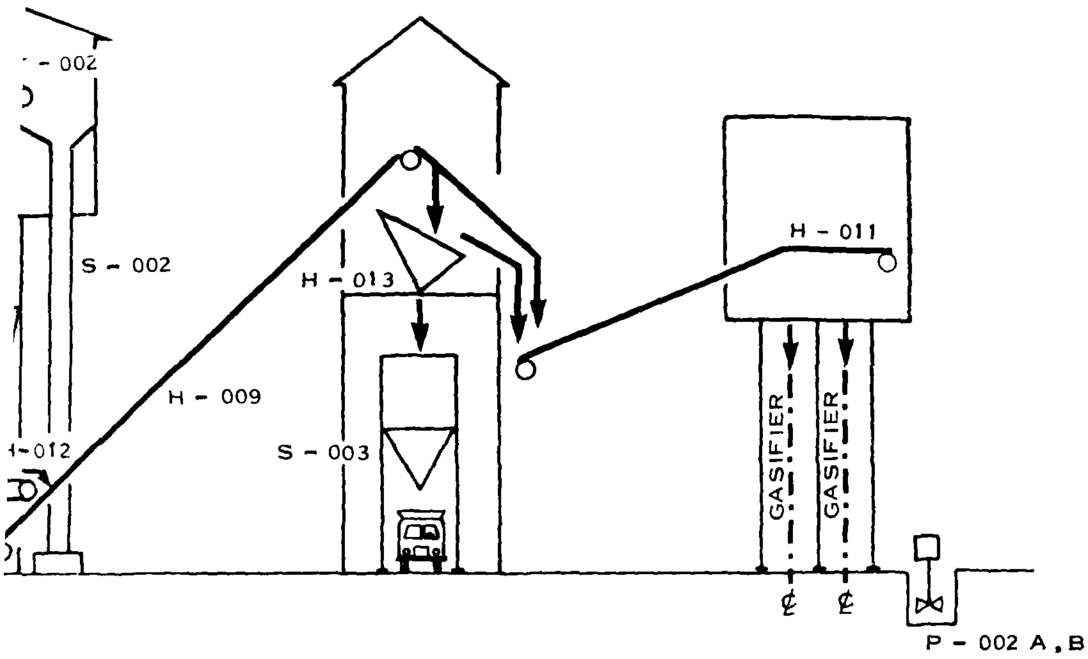
The coal handling flow diagram is shown in Figure 6.1-1.

Sub-bituminous C coal sized at (2" x 0") with 25% fines is delivered to the site in 20 ton trucks. Deliveries are recorded at truck scale T-001.

The trucks discharge either directly on the floor of the storage area or into inground receiving hopper S-001. Spray nozzles control the release of coal dust during truck unloading into the receiving hopper which is located in an enclosed structure. Coal discharged directly onto the floor is dozed either to the emergency storage pile, or into the receiving hopper. A typical daily delivery would range from 8 to 12 trucks. Belt feeder H-001 reclaims the coal from the hopper, and transfers it to belt conveyor H-002 which raises the coal and discharges it into Silo S-002. Magnetic separator T-002 at the head end of conveyor H-002 removes tramp iron from the coal stream. Belt Weighfeeder H-012 reclaims coal from Silo S-002 and discharges onto belt conveyor H-009. Conveyor H-009 discharges to a flop gate which directs the coal either to screen H-013 or directly to Tripper Conveyor H-011. Bypass chute



H - 002
GRADE
COAL PILE
T - 001
S - 001
H - 001
P - 001 A, B
G - 001 A, B, C
EXHAUST FROM COAL SILO.
SCREEN ENCLOSURE
AND TRIPPER AREAS
COAL DUST COLLECTION SYSTEM



S - 001	RECEIVING HOPPER
S - 002	COAL SILO
S - 003	FINES SILO
G - 001	DUST COLLECTOR
H - 001	RECEIVING BELT FEEDER
H - 002	BELT CONVEYOR
H - 009	BELT CONVEYOR
H - 011	TRIPPER CONVEYOR
H - 012	SILO BELT WEIGHFEEDER
H - 013	SCREEN
P - 001	SUMP PUMP
P - 002	SUMP PUMP
T - 001	SCALE
T - 002	MAGNETIC SEPARATOR

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FORT GREELY, ALASKA SITE

PROCESS FLOW DIAGRAM

COAL HANDLING AND STORAGE SECTION

FIGURE 6.1-1

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connections are provided for the collection of coal samples prior to discharge to Tripper Conveyor H-001.

Fines less than 1/4" flow from the screen fines hopper into Silo S-003 which is sized for two days storage capacity and which discharges intermittently into enclosed trucks. Bag type dust collectors control dust generated during coal handling and prevent accumulation of methane in coal silo, S-002.

Two 100% capacity sump pumps are installed in the receiving hopper pit to remove accumulated water and any storage pile runoff. Coal dust accumulated at the gasifier area is hosed with water. The water/coal mixture is removed by two 100% capacity sump pumps.

The emergency storage pile is built up with compacted coal layers. By exclusion of oxygen, compacting reduces the probability of spontaneous combustion. Compaction also increases storage capability of the pile.

To prevent escape of coal dust during wind conditions, the storage pile may be sprayed with a commercially available crusting agent which cures in about 12 hours.

Depending upon soil characteristics, an impervious liner may be required under the pile to prevent leachate migration into the ground. Collecting ditches are provided along the pile periphery to collect water runoff.

Due to low prevailing temperatures, conveyors and associated equipment are housed in heated galleries and transfer houses.

6.1.1.3 System Performance

The coal handling system consists of belt conveyors, belt feeders and chutes. Each conveyor consists of belt, idlers, pulleys, a reduction gear, holdback, coupling and an electric motor.

Conservatively designed, a long service life can be expected from these components. Preventive maintenance is simple and replacement parts can be stored at the plant.

6.1.2 Ash Handling System

6.1.2.1 Functions and Design Requirements

The function of the ash handling system is to remove ash collected in the gasifier storage hoppers. Additionally, the design considers the environmental impacts associated with the handling of powder type materials which can be a source of dust emissions.

6.1.2.2 System Description

Ash produced through the gasification of subbituminous coal is collected and stored in a conical hopper located below the revolving grate of each gasifier. With an ash flow rate of 1815 lbs/hr, the gasifier ash hopper requires unloading at least twice per day.

Dust or fly ash entrained in the gas leaving the gasifier is separated in a cyclone separator and collected in its conical storage hopper at the rate of 2.64 tons of dust in a 24 hour period, based on a flow of 220 lbs/hr.

Each hopper is furnished with a sliding gate operated by a manual rack and pinion gear. Ash and dust is unloaded from their respective hoppers into a covered dump truck for offsite disposal. Prior to unloading the ash hopper, an operator floods the hopper with water and then dewaters it before opening the gate. Because of the high CaO content of the ash, water quench time is reduced to prevent binding in the ash and dust hoppers.

Dust collected in the cyclone hopper is stored in a wet state and unloaded with the ash into the covered dump truck.

6.1.2.3 System Performance

The ash removal and handling system utilizing truck disposal provides high reliability and availability. It is assumed that the trucking operation will be performed on a contract basis and that certain guarantees in the contract will be made to assure daily removal of ash and dust.

6.1.2.4 Maintenance

Operation of this system is local and manual. Manual loading of materials into containers, vehicles, etc., is the most widely used method and by far the simplest. Control of the ash hopper flood cycle is also local and operator initiated. With a proper preventive maintenance program implemented, critical components such as isolating gates should not fail during operation.

6.1.2.5 Technical Risks

Among the risks associated with ash and dust removal is the availability of trucks to receive the ash and dust, failure of the isolating gate to operate at low temperatures and freezing of ash or dust in the hoppers. During severe weather or other events which prevent trucks from removing ash and dust, dumpsters provide temporary onsite storage.

Manual operation of the gate valve during unloading of hoppers and periodic inspections to detect gate valve blade wear assure reliable operation.

Freeze protection by heat tracing (e.g., of water lines to hoppers) and by heated enclosures is also provided.

6.2 Coal Gasification

6.2.1 Functions and Design Requirements

The function of the Coal Gasification Section is to convert coal energy to gaseous form suitable for processing prior to its use in a fuel cell.

The controlling design criteria for the Coal Gasification Section is the concentration of carbon, hydrogen and volatile matter in the design coal. The feedstock used for this study is a locally available subbituminous coal with composition and characteristics shown in Table 6.2-1.

Design capacity of the gasifier is based on the Westinghouse fuel cell requirement of 556 mols of hydrogen per hour.

A fixed bed air blown atmospheric single stage Wellman-Galusha gasifier was selected as the basis for this study. This selection was based primarily on the decision to use fully commercialized technology. The Wellman-Galusha gasifier having been in use for 50 years has a large data base of technical and economic information. Another criteria for gasification technology selection was the size of the gasifier. This fuel cell system requires a relatively small gasification plant eliminating larger gasifiers from use in this application.

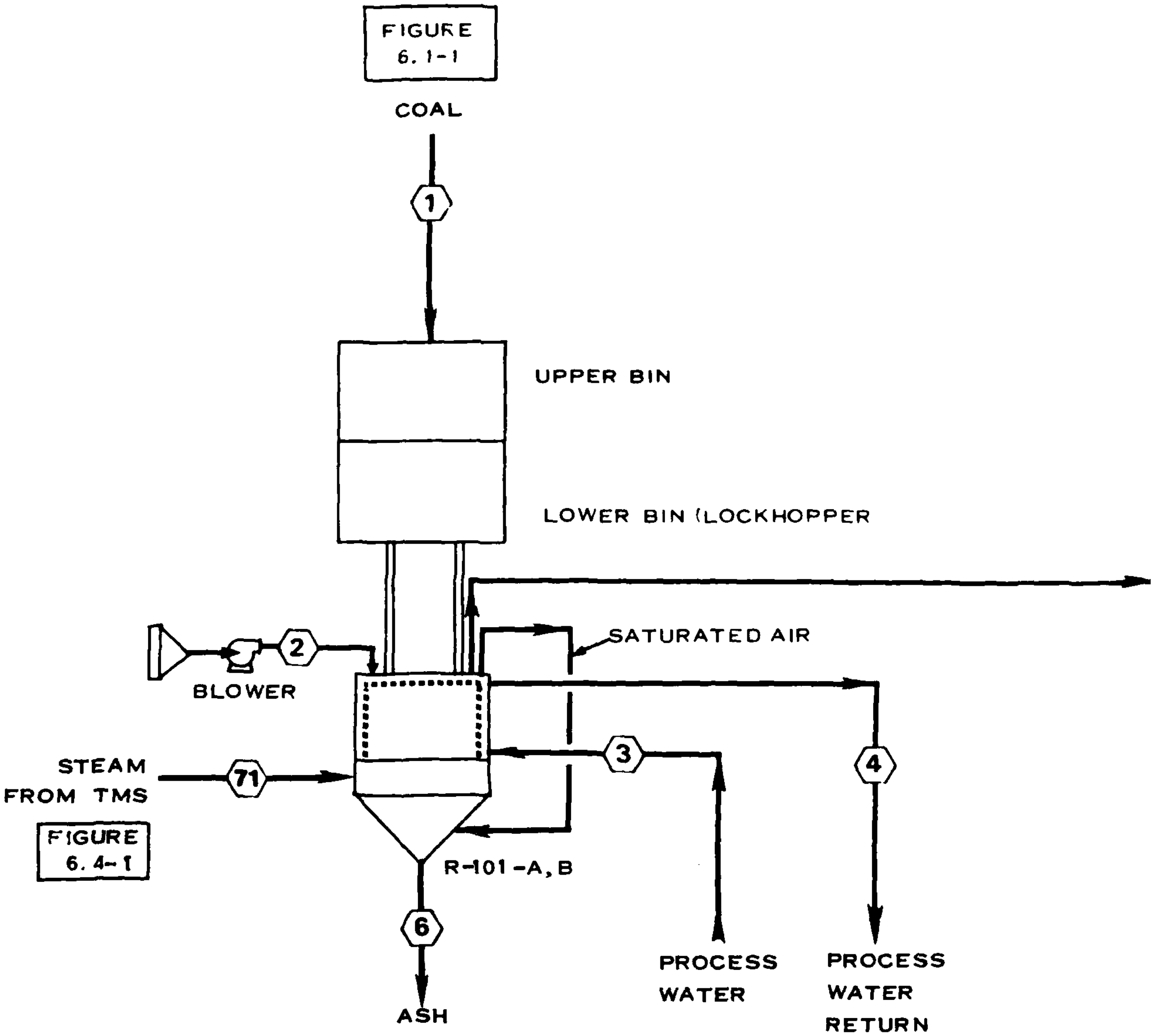
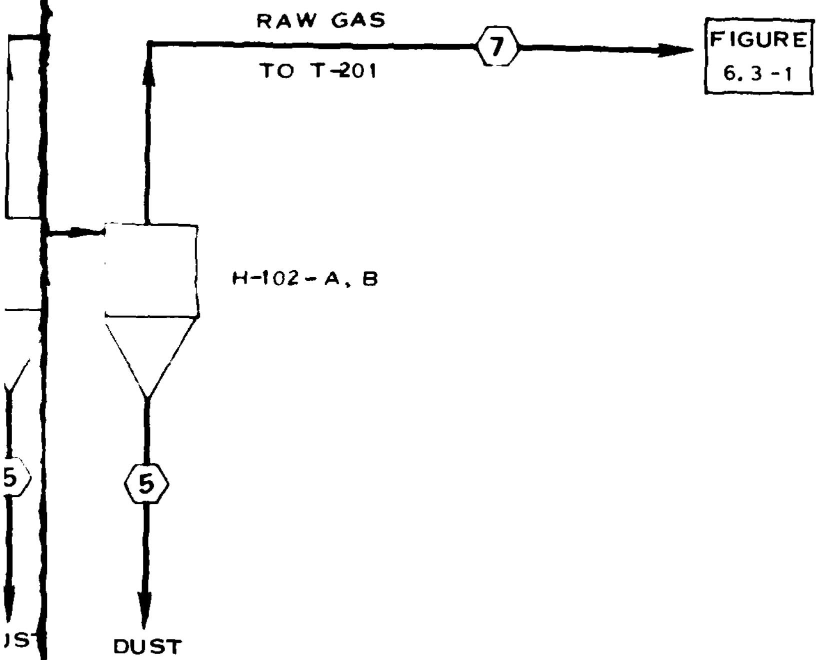


FIGURE
6.1-1
COAL
1
UPPER BIN
LOWER BIN (LOCKHOPPER
SATURATED AIR
2
BLOWER
STEAM
FROM TMS
71
FIGURE
6.4-1
3
4
R-101-A, B
6
ASH
PROCESS
WATER
PROCESS
WATER
RETURN



R-101-A, B	GASIFIER
H-102-A, B	CYCLONE

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COAL GAS / FUEL CELL / COGENERATION

FORT GREELY, ALASKA SITE
PROCESS FLOW DIAGRAM

COAL GASIFICATION SECTION

FIGURE 6.2-1

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In addition, the Wellman-Galusha unit is able to process coal with a Free Swelling Index up to 5 covering a wider range of coals than comparable technologies.

The raw gas composition produced by the Wellman-Galusha gasifier from the design coal is shown in Table 6.2-2.

The total consumption of coal by the gasifiers is 175.6 T/day producing 1,939 million Btu/day of coal gas at a gasification efficiency of 72%. If the heating value of tars and oils is included, the efficiency increases to 86%.

The material balance for the gasifier is given in Table 6.2-3.

TABLE 6.2-1

COAL ANALYSIS

o COAL (SUBBITUMINOUS C)

Proximate Analysis (as received, %)	
Moisture	23.8
Ash	12.2
Volatiles	36.1
Fixed Carbon	25.7
Ultimate Analysis (dry basis %)	
Carbon	57.2
Hydrogen	4.5
Nitrogen	0.8
Sulfur	0.3
Chlorine	-
Ash	16.0
Oxygen (by diff)	21.2
Higher heating value (as rec'd Btu/Lb)	7,510
Ash Fusion, Initial Def. Temp (°F)	2,309 (Red.)
Free Swelling Index	1.0

TABLE 6.2-2

RAW GAS COMPOSITION

	Mol %	(Dry Basis)
H_2	18.95	
CO_2	7.02	
C_2H_4	0.16	
C_2H_6	0.13	
N_2	45.66	
CH_4	1.65	
CO	26.30	
H_2S	0.06	
COS	60 ppm	
NH_3	0.06	
HCN	60 ppm	
	100.00	

Water Yield Lb/Lb Coal	0.47
Tar Yield Lb/Lb Coal	0.06
Gas Temperature °F	480

TABLE 6.2-3

GASIFIER MATERIAL BALANCE

INPUT		LB/HR
Coal Feed (As received)		14,637
Air, Dry		20,931
Steam		4,537
	Total	40,105

OUTPUT		
Dry Gas		30,313
Tars and Oils		878
Water Vapor		6,879
Ash Purge		1,815
Cyclone Dust		220
	Total	40,105

6.2.2 System Description

The process flow diagram for the gasification system is shown on Figure 6.2-1 and the mass balance in Table 6.2-4.

At the top of each Wellman-Galusha gasifier (R-101 A & B) is an open coal bunker or "upper bin". Following that in the downward direction is a gas tight lower coal bin or "lockhopper" in the gasifier reactor vessel and finally, the ash cone at the bottom(2)(3).

The upper bin is filled by the bucket elevator and discharges coal by gravity into the lower bin. The lower bin has interlocking gas tight valves top and bottom configured such that the bottom valves close before the top valves open, and vice versa. The upper valves open, allowing coal to flow by gravity into the lockhopper. When the lockhopper is filled, usually in a matter of a few minutes, the valves are cycled, closing the upper valves and opening those at the bottom.

The lower fuel valves are kept open, except for refueling, to assure a continuous supply of fuel into the gasifier reactor vessel.

The gasifier R-101 is a double wall cylindrical vessel, with an inner shell of one inch thick steel. A water jacket surrounds the side of the inner shell and extends over the top. About four inches above the top of the inner wall there is an overflow pipe which prevents the water from completely filling the space between the inner and outer shell at the top of the vessel. Cooling water is introduced into the water jacket at the top of the vessel, and flows out through the overflow.

Air to sustain combustion is supplied by a blower. After absorbing moisture as it passes over the open water surface in the top of the water jacket, the air enters the gasifier vessel from below the grate plates, flowing upward through the ash bed. The moisture carried by the air flow moderates the temperature of the fire bed preventing the formation of clinkers. The amount of water vapor absorbed depends upon jacket water temperature which is controlled by varying cooling water flow. To supplement the water vapor introduced with the air stream, steam is

injected at the bottom of the gasifier vessel. The water thus introduced reacts chemically with the hot carbon, generating gaseous products.

Coal flowing down through the feed pipes enters the top of the gasifier and is contacted by the upward flow of hot gas produced in the gasifier reactor. Heat from the countercurrent flow of hot gas evaporates moisture then drives off volatiles in the incoming coal. This moisture and volatile matter become part of the gas stream. The dry devolatilized coal char continues its slow downward flow through the gasifier at a rate determined by the air flow into the unit which, in turn, sets the gasification rate. The coal char passes through two stages. The first stage consists of a reducing zone, where carbon dioxide produced from char which is burning below is reduced to carbon monoxide. Water vapor is also reduced in this zone by the hot carbon in the char, producing hydrogen and additional carbon monoxide. The heat supporting this endothermic reaction is produced by the first zone directly below, wherein the carbon in the char is burned to form carbon dioxide.

The burning coal in the fire zone rests upon a bed of ash produced by the combustion of the coal char, and this bed of ash in turn is supported by a slowly revolving set of eccentric grates.

Ash removed from the gasifier vessel by the revolving grate drops into an ash cone at the bottom of the vessel. From there it is flushed out periodically with water into a truck. Flushing the ash is of a few minutes duration and does not interfere with the normal operation of the gasifier.

The depth of the ash and fire zones is monitored by the insertion of rods through pokeholes located on top of the gasifier. Steam sealed pokeholes are used to prevent gas leaks during the poking operations.

The hot gas produced in the gasifier contains particulates and moisture and tangentially enters dust cyclone H-402, which separates particulates from the gas stream. The hot gas then flows directly to gas cleaning equipment. Composition of the gas at this point is shown in Table 6.2-2[3].

The cyclone is designed to be used as a water sealed gas shut-off valve and provides a positive leak-proof shut-off without the use of a mechanical valve. The separated particulates are stored in the cyclone cone section and flushed into a truck at the same time the wet ash is unloaded from the gasifier, in order to minimize dust emissions.

6.2.3 System Performance

The Wellman-Galusha gasifier is rated at a capacity of 8000 lbs/hr for this coal. In commercial operation, the gasifier has processed as little as 7.5 pounds of coal per square foot of grate per hour or about 20% of capacity. This makes it possible to operate the gasifier without venting the excess gas to atmosphere when the demand is small. The gasifier can be operated at part load without a loss in efficiency(4). The gasifier has no refractory lining in the gas making chamber, eliminating liner maintenance, a primary cause of shutdown for other types of gasifiers. A two week scheduled annual shutdown for maintenance with an estimated three days of unscheduled shutdown brings the estimated availability of the gasifier to 95%. Gasification will proceed at a total coal flow rate of 14,637 lbs/hr to two gasifiers. Each gasifier operates at 91% capacity based on the material balance in Table 6.2-3.

6.2.4 Maintenance

The maintenance work anticipated for the section is minimal and requires the daily flushing of the gasifier jacket. During the scheduled two week annual shutdown, repair or replacement is made as required of the moving grates, bearings, or other moving parts. Lockhopper disk valves are cleaned and poke hole seal valves are checked.

TABLE 6.2-4

MASS BALANCE - COAL GASIFICATION SECTION

Stream No.		1	2	3	4	5	6	7	71
Stream Name		Coal	Air	Gasifier Jacket Water Inlet	Gasifier Jacket Water Outlet	Cyclone Dust	Ash Purge	Producer Gas	Gasifier Steam
			Lb Mol/hr	Lb Mol/hr	Lb Mol/hr	Lb Mol/hr	Lb Mol/hr	Lb Mol/hr	Lb Mol/hr
Components	MW								
H_2	2.016							239.46	
CO_2	44.010							88.71	
C_2H_4	28.032							2.02	
C_2H_6	30.048							1.64	
N_2	28.016		572.96					576.98	
CH_4	16.032							20.85	
CO	28.011							332.34	
H_2S	34.080							0.70	
COS	60.070							0.08	
NH_3	17.030							0.76	
HCN	27.030							0.08	
O_2	32.000		152.30						
Ar	39.948								
H_2O (Water)	18.016			2,112.12	1,990.29				
H_2O (Steam)	18.016		8.13					381.83	121.84
Total Flow	lb Mol/hr		733.39	2,112.12	1,990.29			1,645.45	121.84
Total Flow	Lb/Hr	14,637	21,077	38,052					2,195
Solids	Lb/Hr					220	1,815		
Tar	Lb/Hr							878	
Pressure	Psia		14.7					15	25
Temperature	°F		68	90	160			480	240

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6.2.5 Technical Risks

The mechanical components of the gasifier can be considered as potential technical risks. These components include the coal feed system and the moving grates. However, potential problems in these areas have been virtually eliminated by design improvements made in the course of many commercial applications[4].

The coal feeding system has no moving parts, thus eliminating the problems common to machines where mechanical devices are used on highly abrasive fuels. The design features now include replaceable bushings and oversized ball thrust bearings with oil and grease dams for the revolving grate assembly. Because of such design features the technical risk for the mechancial components is minimal.

Consideration must be given to the possibility that the feed coal contains more fines than anticipated or that gasifier performance will be affected with a fines content less than 15%. If the fines fed to the gasifier is excessive, tne flow through the coal bed can be restricted, and there can be high carryover of ungasified coal particles into the cyclone with significant impact on gasification efficiency. To eliminate this as a technical risk, coal is screened before transfer to the conveyor feeding the gasifier upper bins.

6.2.6 References

6.2-1 Synthetic Fuels Associates, Inc, "Coal Gasification: A Guide to Status, Applications and Economics", EPRI AP-3109, June 1983.

6.2-2 Wellman Gasification Technology - Technical Manual

6.2-3 Personal Communication with Dravo Engineers, Inc.

6.2-4 Wellman-Galusha Gas Producers, Dravo

6.2-5 Gas Engineers Handbook, the Industrial Press, 1965

6.3 GAS PROCESSING

6.3.1 Functions And Design Requirements

The function of the Gas Processing System is to cool, clean and compress the gasifier effluent and then convert it to a hydrogen rich, sulfur free stream suitable as feed for the fuel cell. This section also includes a Process Condensate Treatment Section, where the toxic and organic matter are removed from the process waste water to satisfy environmental requirements before discharge.

The design criteria for the Gas Processing System is the anode feed gas specification given in Table 6.4-1. The design criteria for the Process Condensate Treatment Section is the waste water effluent specification, given in Table 6.3-1.

6.3.2 System Description

The Gas Processing System includes the following sections:

- Gas Cooling, Cleaning and Compression
- CO Shift
- Sulfur Removal and Recovery
- Process Condensate Treatment

The gasifier effluent is at 480°F and contains tars, oils, phenol, ammonia and particulates that must be removed before further processing. The processes used to cool and clean the raw gas by spraying with water followed by removal of condensed hydrocarbons in an electrostatic precipitator, have been traditionally used and improved over the years in the coke oven industry and fixed bed gasifiers product gas cleaning(1).

TABLE 6.3-1

TREATED PROCESS EFFLUENT CHARACTERISTICS[1]

	mg/1
COD[2]	150
Phenol	0.3
HCN	0
NH_3	1
H_2S	0
Suspended Solids	20

Notes:

1. Personal communication with Zimpro Environmental Control Systems.

2. COD = Chemical Oxygen Demand.

In the CO Shift Section the hydrogen (H_2) concentration in the gas is adjusted to the requirements of the fuel cell by conversion of the carbon monoxide (CO) to H_2 by reaction with steam over a catalyst.

The presence of sulfur compounds in the fuel gas led to the selection of a highly active sulfur tolerant chromium-molybdenum (COMO) shift catalyst. The catalyst is activated by small amounts of sulfur in the gas and is active within a wide range of temperatures. Part of the carbonyl sulfide (COS) present in the gas is hydrolized in the process and converted to H_2S and CO_2.

Another option was to remove the sulfur compounds first and use a conventional iron-chromium catalyst for the CO Shift reaction.

The choice of a sulfided shift process was determined by the selection of the Sulfur Removal process, which does not remove the carbonyl sulfide (COS) present in the gas. This sulfur compound, even in trace amounts, would poison a conventional CO Shift catalyst.

A two stage shift reaction with the second bed operating at lower temperatures was selected for this application. Both reactions, the CO shift and the COS hydrolysis take place simultaneously, but the bulk of COS hydrolysis occurs in the second bed. This design will achieve the desired CO conversion and will reduce the COS concentration in the gas to about 5 ppm by volume.

The specifications for the anode fuel require a maximum sulfur content of 4 ppm (Vol). Virtually, total sulfur removal from the gas must be achieved.

There are a number of sulfur removal processes commercially available, for treating the H_2S bearing gases(3)(4). These processes include chemical and physical absorption systems, which remove the sulfur compounds from the gas down to the desired level.

The physical absorption processes require low temperature operation and high H_2S partial pressure. The chemical absorption processes are not selective and remove CO_2 with the H_2S. The regeneration of the solvent requires large steam consumption to strip the absorbed gases, especially with the addition of CO_2.

The selection of a sulfur removal process was based on gas composition considerations. The gas produced by an atmospheric gasification such as the Wellman-Galusha gasifier has a very low H_2S partial pressure due to the dilution of the gas with the nitrogen from the air used in the gasification process and the relatively low gas pressure, even after compression to 160 psia. This low H_2S partial pressure eliminates the physical absorption systems as possible process choices. The chemical absorption processes are a costly alternative for the sulfur recovery process due to the high CO_2 concentration in the gas (26% Vol).

Therefore, a Stretford liquid oxidation process was chosen for this plant. In this process, the H_2S in the gas is absorbed in a solution where it is chemically oxidized to sulfur and water. The sulfur is separated from the solution, which is regenerated by air-sparging and recycled.

The traces of H_2S in the gas are removed in a polishing step over ZnO beds.

The condensate from the gas cooling section contains phenols, ammonia, cyanides and hydrogen sulfide. To prevent the buildup of these products in the circulating waste water, a purge stream is removed from the process condensate and discharged as waste water effluent. Before being discharged the waste water is treated for the removal of the pollutants. Two processes were considered to be used for this purpose; the Wet Air Oxidation Process (WAO) and the Powdered Activated Carbon Treatment (PACT)[8]. The PACT process uses powdered activated carbon in conjunction with conventional biological treatment to remove contaminants and was selected to be used in this plant because it has substantially lower investment costs than the Wet Air Oxidation Process for this size unit.

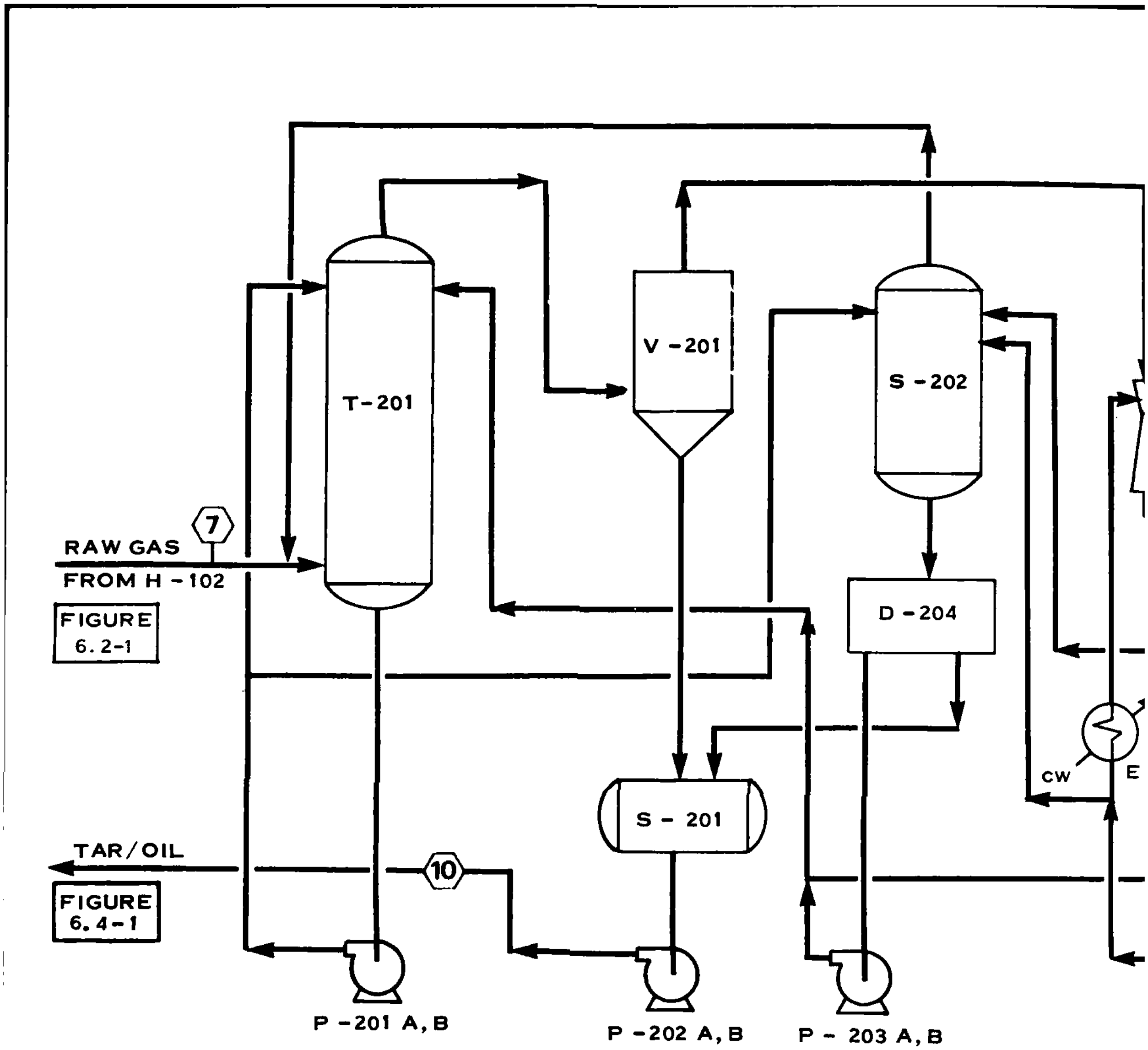
Process Description

Gas Cooling, Cleaning and Compression

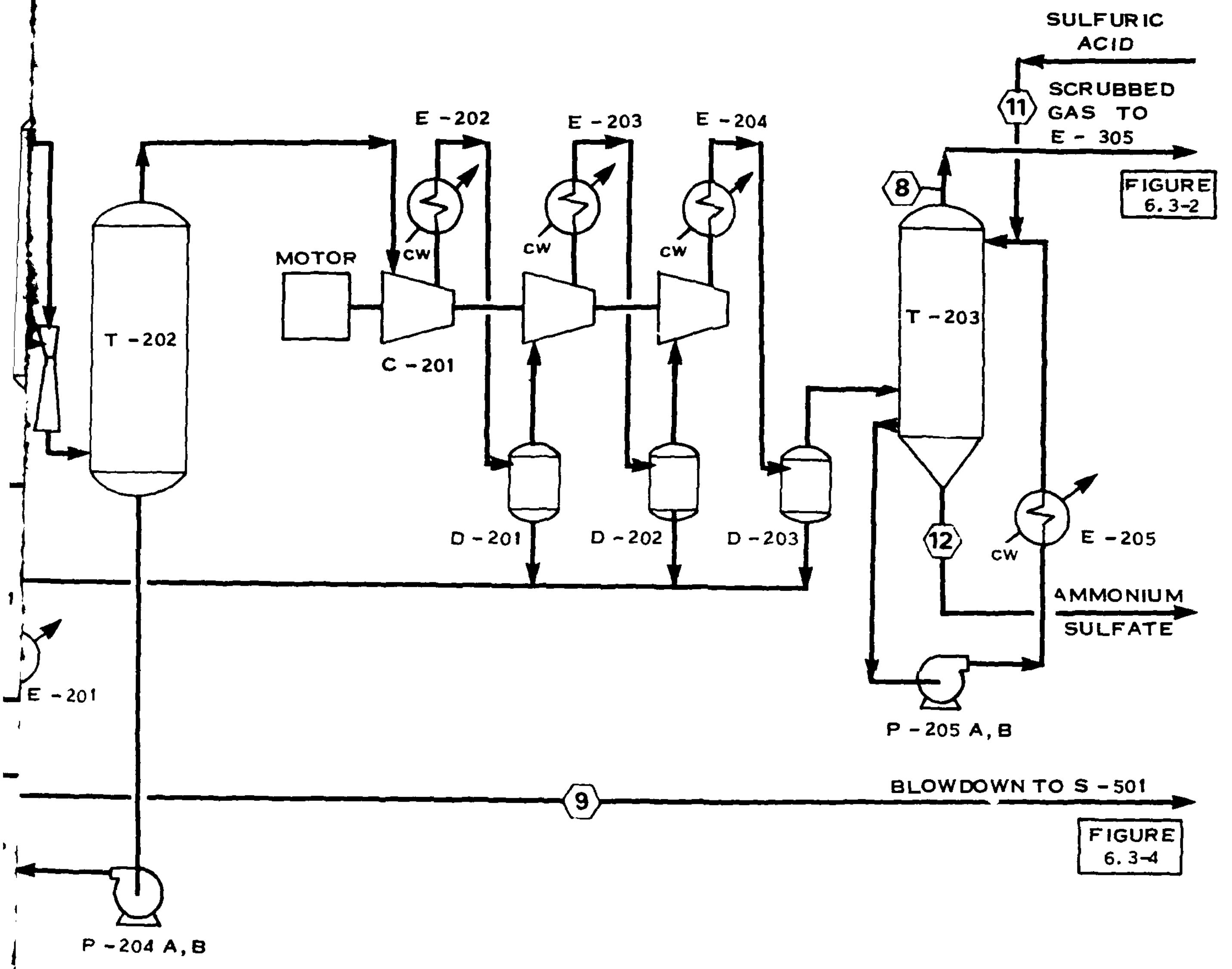
The configuration of the Gas Cooling, Cleaning and Compression Section is given in Figure 6.3-1 and the Mass Balance in Table 6.3-2.

The hot gas leaving the gasification section contains entrained particuates. Before compression, the gas must be cooled and the particulates removed. The gas is first cooled by boiler feed water in heat exchanger E-206 thus contributing to the generation of 30 psig steam. This steam is used in the Waste Water Treatment Section for ammonia stripping with the excess steam sent to the Thermal Management Section.

Final cooling and cleaning of the gas occurs in primary cooler, T-202 by contact of the gas with circulating liquor in a venturi jet . The concentration of ammonia, phenols and particulates in the wash liquor is prevented by purging a slip-stream from the recycle stream to the venturi jet. This blowdown is sent to the Waste Water Treatment Section. Make-up water enters at the top of tower T-202.



T -201	SATURATOR	P -201 A, B	SATURATOR PUMP
V -201	DISPERSED PHASE PRECIPITATOR	S -201	TAR COLLECTION TANK
D -204	TAR SEPARATOR	P -202 A, B	TAR PUMP
S -202	LIQUOR COLLECTION TANK	P -203 A, B	LIQUOR PUMP
T -202	PRIMARY COOLER	P -204 A, B	PRIMARY COOLER PUMP
C -201	GAS COMPRESSOR	D -201	1ST STAGE K.O. DRUM
E -202	1ST STAGE INTERCOOLER	D -202	2ND STAGE K.O. DRUM
E -203	2ND STAGE INTERCOOLER	D -203	3RD STAGE K.O. DRUM
E -204	3RD STAGE INTERCOOLER	P -205 A, B	ACID CIRCULATION PUMP
T -203	AMMONIUM SULFATE SATURATOR	E -205	AMMONIUM SULFATE SATURATOR COOLER



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FORT GREELY, ALASKA SITE
PROCESS FLOW DIAGRAM
GAS COOLING, CLEANING AND COMPRESSION SECTION
FIGURE 6.3-1

EBASCO SERVICES INCORPORATED

TABLE 6.3-2

MASS BALANCE - GAS COOLING, CLEANING AND COMPRESSION SECTION

Stream No.		7	8	9	10	11	12
Stream Name		Producer Gas	Compressed Gas	Process Condensate Blowdown	Tars/Oils	Sulfuric Acid	Ammonium Sulfate
Components	MW	Lb Mol/hr	Lb Mol/hr	Lb Mol/hr	Lb Mol/hr	Lb Mol/hr	Lb Mol/hr
H_2	2.016	239.46	239.46				
CO_2	44.010	88.71	87.50	1.21			
C_2H_4	28.032	2.02	2.02				
C_2H_6	30.048	1.64	1.64				
N_2	28.016	576.98	576.98				
CH_4	16.032	20.85	20.85				
CO	28.011	332.34	332.34				
H_2S	34.080	0.70	0.70				
COS	60.070	0.08	0.08				
NH_3	17.030	0.76	-	0.57			
HCN	27.030	0.08	0.08				
O_2	32.000						
Ar	39.942						
H_2O (water)	18.016			371.83			
H_2O (steam)	18.016	381.83	10.0				
Total Flow	lb Mol/hr	1,645.45	1,271.65	373.61			
Total Flow	Lb/Hr						
Tars/Oils	Lb/Hr	878			878		
Sulfuric Acid	Lb/Hr					9.3	
Ammonium Sulfate	Lb/Hr						12.5
Pressure	Psia 15	15	117	17			
Temperature	°F	480	100	100			

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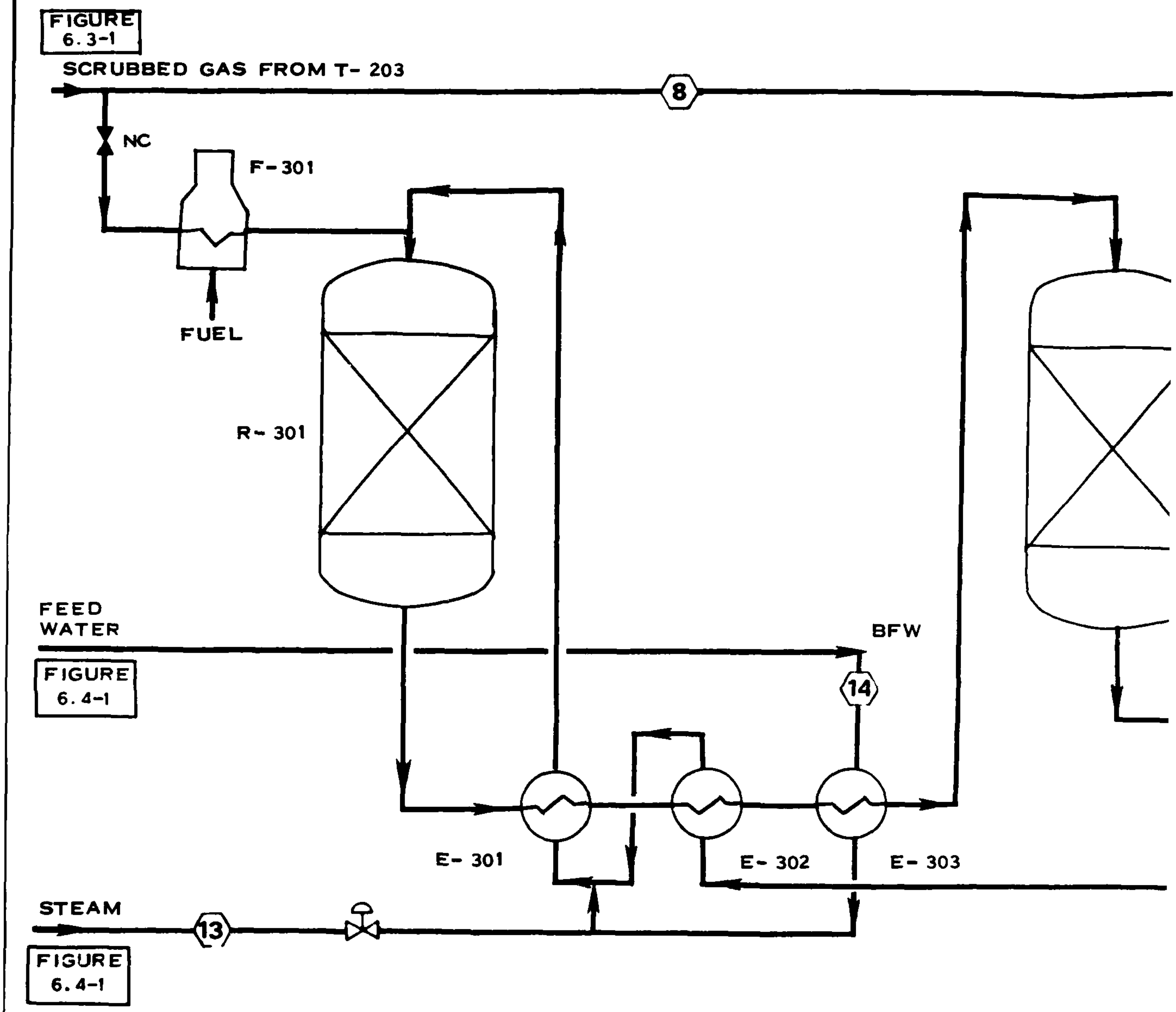
Multistage centrifugal compression (C-201) with interstage cooling is provided to increase the gas pressure. Condensate produced in the water cooled interstage coolers is returned to the primary cooler, T-202.

The compressed and cleaned gas leaving the section is washed with sulfuric acid in Ammonium Sulfate Saturator T-203 to remove ammonia not scrubbed out in the cooling and cleaning of the gas. The heat of this neutralization is removed by circulating the wash liquor through an external heat exchanger E-205. The ammonia-free gas exits to the CO Shift section.

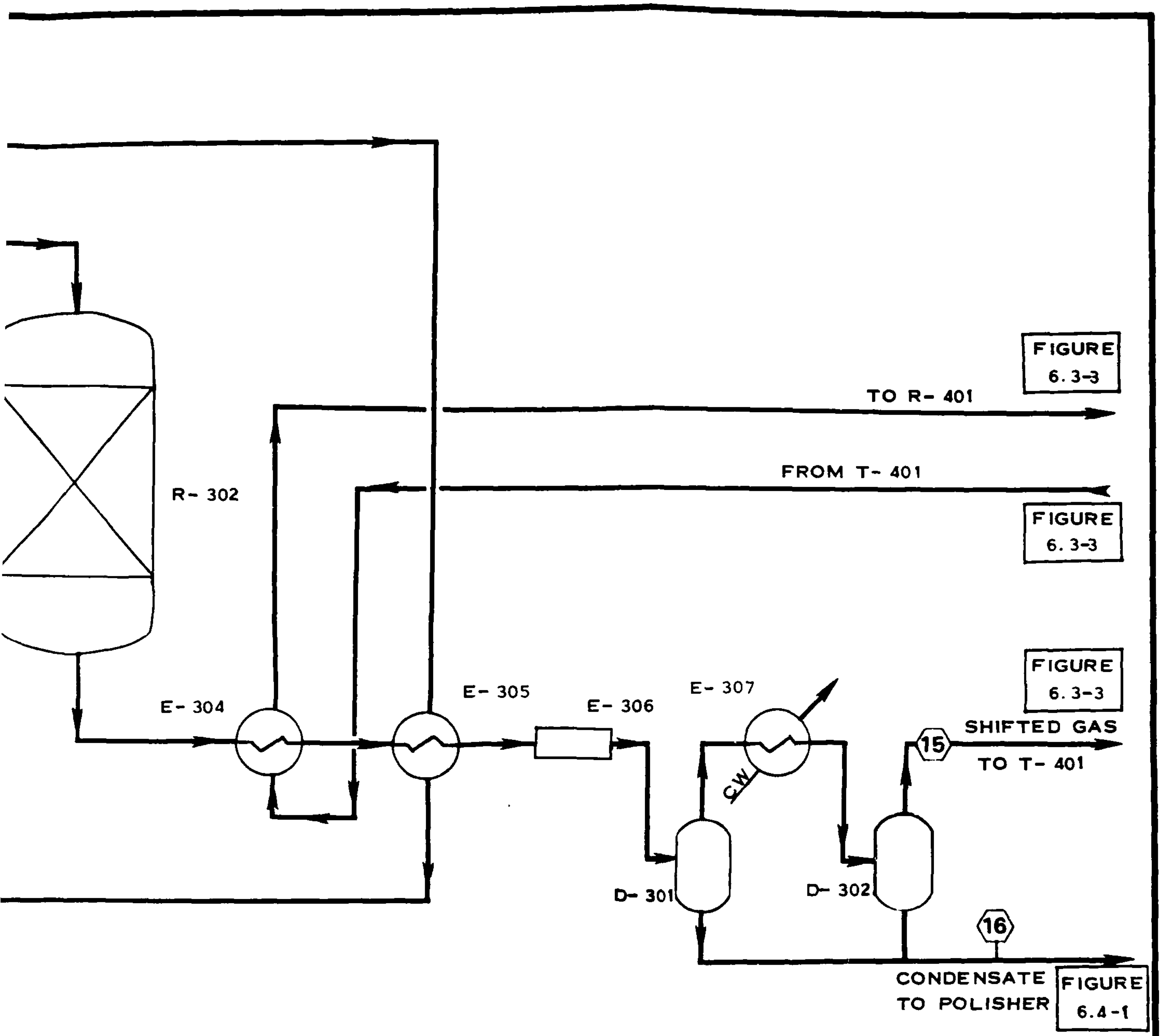
CO Shift

The CO Shift reaction is carried out in two stages. It is a highly exothermic reaction and the heat of reaction is used to preheat the feed to the first stage to raise steam and to preheat the clean gas before the final polishing.

The configuration of the CO Shift Section is shown in Figure 6.3-2 and the Mass Balance in Table 6.3-2. The temperature of scrubbed gas leaving the gas compression section is raised in preheaters E-305 and E-302 followed by direct injection of medium pressure steam. Upon further preheating with 1st shift effluent in heat exchanger E-301, the wet gas is introduced into the first stage reactor, R-301. After the reaction, the first stage effluent is cooled by heat exchange with the feed. Further heat recovery takes place by generation of medium pressure steam, and the cooled first stage effluent is introduced into the second stage of water gas shift reactor, R-302.



D-301	K.O. DRUM	E- 305
D- 302	TRIM COOLER K.O. DRUM	E- 306
E-301	FEED/EFFLUENT HEAT EXCHANGER II	E- 307
E- 302	FEED/EFFLUENT HEAT EXCHANGER I	F- 301
E- 303	CO SHIFT STEAM GENERATOR	R- 301
E- 304	FUEL CELL FEED HEATER	R- 302



E- 305	FEED GAS PREHEATER
E- 306	AIR COOLER
E- 307	TRIM COOLER
F- 301	START-UP HEATER
R- 301	1ST CO SHIFT REACTOR
R- 302	2ND CO SHIFT REACTOR

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PROCESS FLOW DIAGRAM
CO SHIFT SECTION

FIGURE 6.3-2

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TABLE 6.3-3

MASS BALANCE - CO SHIFT SECTION

Stream No.		8	13	14	15	16
Stream Name		Compressed Gas	Shift Steam	Boiler Feedwater	Shifted Gas	Condensate
Components	MW	Lb Mol/hr	Lb Mol/hr	Lb Mol/hr	Lb Mol/hr	Lb Mol/hr
H_2	2.016	239.46			556.12	
CO_2	44.010	87.50			405.51	
C_2H_4	28.032	2.02			2.02	
C_2H_6	30.048	1.64			1.64	
N_2	28.016	576.98			576.98	
CH_4	16.032	20.85			20.25	
CO	28.011	332.34			15.64	
H_2S	34.080	0.70			0.77	
COS	60.070	0.08			0.008	
NH_3	17.030	-			-	
HCN	27.030	0.08			0.08	
O_2	32.000					
Ar	39.948					
H_2O (Water)	18.016			98.25		413.65
H_2O (Steam)	18.016	10.0	671.04		34.00	
Total Flow	Lb Mol/Hr	1,271.65	671.04	98.25	1,613.62	413.65
Total Flow	Lb/Hr		12,090	1,770		7,452
Pressure	Psia	117	120	120	80	
Temperature	°F	100	341	237	120	120

The second stage shift operates at a temperature lower than the first, permitting further reaction of CO to generate more hydrogen and to reduce the CO content to the desired level.

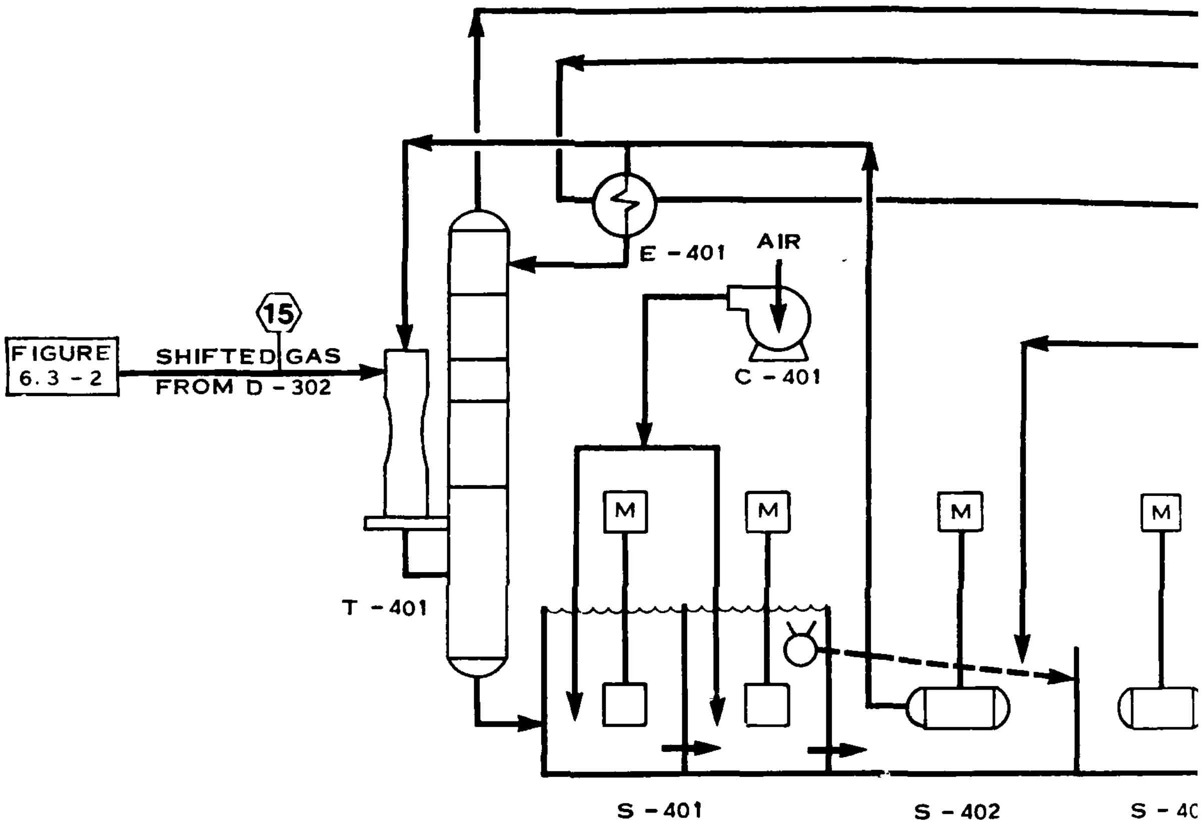
Second stage shift effluent is cooled by preheating anode feed gas in E-304 and preheating raw gas feed to the first stage shift. Additional cooling of the shifted gas to a temperature suitable for its introduction to the Desulfurization Section is accomplished by air and water cooling. Steam condensate resulting from gas cooling is sent to the Thermal Management System. During process startup, gas or oil fired heater, F-301 raises the temperature of the feed gas to the level required for the shift reaction.

Sulfur Removal and Recovery

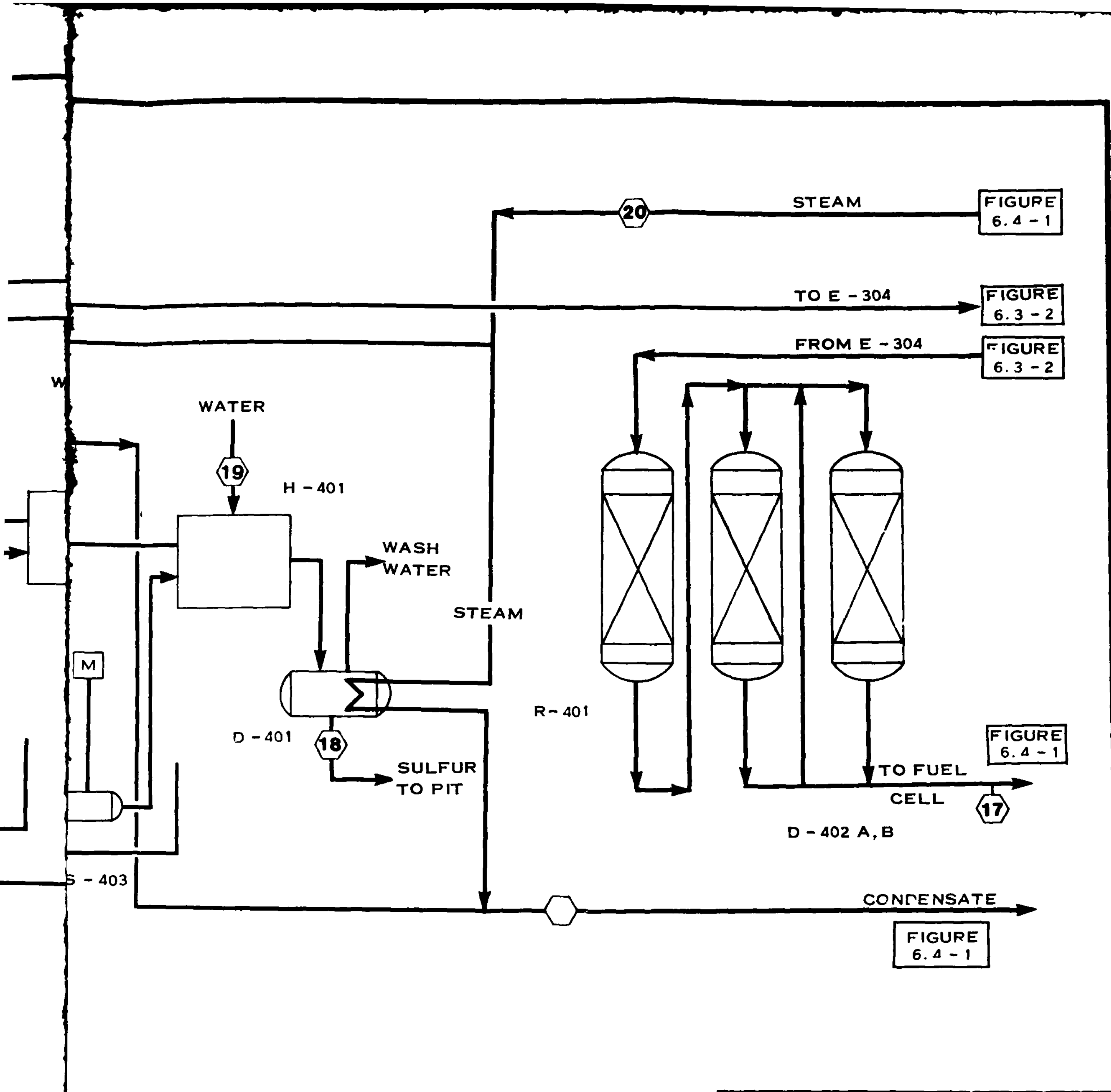
The Sulfur Removal and Recovery Section is shown in Figure 6.3-3 and the Mass Balance given in Table 6.3-4.

This section is designed to reduce the total sulfur content of the gas to 4 ppm, a level acceptable for the fuel cell operation and for compliance with the sulfur emission levels of the plant. A liquid phase oxidation Stretford Sulfur Removal Process is used for the removal of H_2S to the required level.

The shifted gas stream is directed to venturi contactor, T-401 which consists of a venturi type jet mixer and an absorber with an alkaline solution containing sodium vanadate. The H_2S is oxidized by the sodium vanadate to elemental sulfur and water. The solution is sent to oxidizer tank S-401 where by air spraying, and in the presence of anthraquinone disulfuric acid (ADA) the vanadium is oxidized regenerating the alkaline solution and the product sulfur is separated by flotation. The regenerated solution is sent to balance tank, S-402 and recycled to the absorber. The sulfur slurry, separated from the solution, flows to slurry tank S-403 and is separated from other chemicals by filtering and water washing. The sulfur is then reslurried with wash water and heated to the melting point. The molten sulfur flows from decanter, D-401 to the sulfur pit. Chemicals are returned to the system and the wash water discarded.



T - 401	VENTURI CONTACTOR
E - 401	SOLUTION HEATER
C - 401	AIR BLOWER
H - 401	SOLID SEPARATION WASH & RESLURRY
D - 401	SLURRY DECANTER
D - 402 A, B	ZnO DRUM
R - 401	HYDROLYSIS REACTOR
S - 401	OXIDIZER TANKS
S - 402	BALANCE TANK
S - 403	SLURRY TANK



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PROCESS FLOW DIAGRAM
SULFUR REMOVAL AND
RECOVERY SECTION

FIGURE 6.3-3

EBASCO SERVICES INCORPORATED

TABLE 6.3-4

MASS BALANCE - SULFUR REMOVAL AND RECOVERY SECTION

Stream No.		15	17	18	19	20
Stream Name		Shifted Gas	Fuel Cell Fuel Gas	Sulfur Product	Wash Water	Steam to Sulfur Slurry
Components Mol/hr	MW	Lb Mol/hr	Lb Mol/hr	Lb Mol/hr	Lb Mol/hr	Lb
H_2	2.016	556.12	556.12			
CO_2	44.010	405.51	405.51			
C_2H_4	28.032	2.02	2.02			
C_2H_6	30.048	1.64	1.64			
N_2	28.016	576.98	576.98			
CH_4	16.032	20.85	20.85			
CO	28.011	15.64	15.64			
H_2S	34.080	0.77	0.0008			
COS	60.070	0.008	0.0006			
NH_3	17.030	-	-			
HCN	27.030	0.08	-			
O_2	32.00					
Ar	39.948					
H_2O (Water)	18.016					
H_2O (Steam)	18.016	34.00	34.00			
Total Flow	Lb Mol/Hr	1,613.62	1,612.76	0.77		
Flow Flow	Lb/Hr			24.6	350	80
Pressure	Psia	80	70			65
Temperature	°F	120	375			298

Product gas leaving the absorber is preheated to 375°F (the fuel cell temperature) in the CO Shift Section before being returned to the Gas Desulfurization Section for final polishing.

The final polishing process protects the fuel cell power section from sulfur poisoning in the event of an upset in the sulfur removal plant. The H_2S is removed down to the required level by absorption in a zinc oxide bed. The final polished gas is then sent to the fuel cell anode.

In the Stretford process, there is a by-product fixation of H_2S into thiosulfate[7]. To avoid the accumulation of thiosulfate and thiocyanate, the solution is purged by removing a slip stream which is sent off-site for disposal.

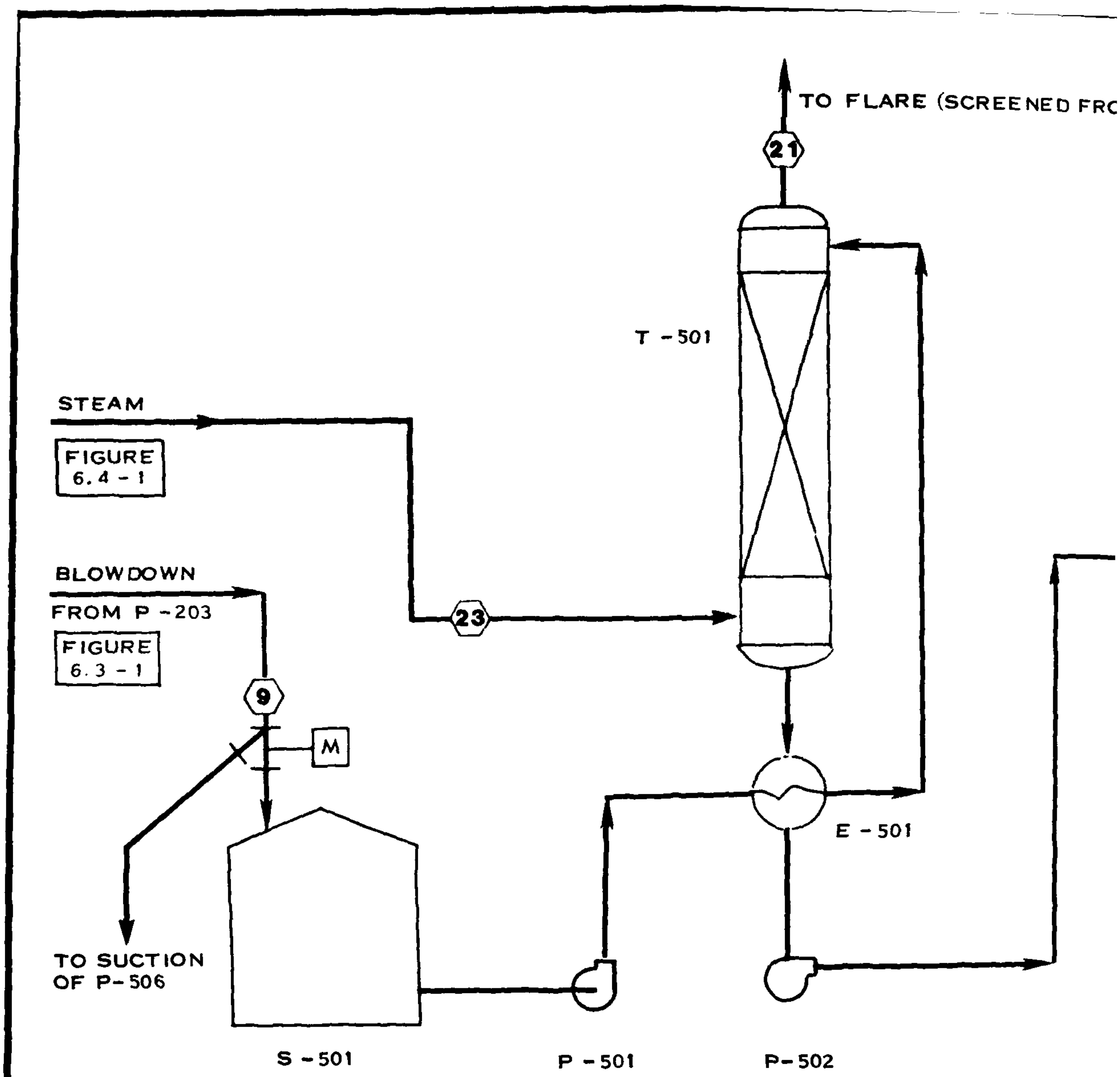
Process Condensate Treatment

The Process Condensate Treatment Section is shown in Figure 6.3-4 and the mass balance given in Table 6.3-5.

Waste water leaving the plant will be continuously monitored for excessive levels of phenol, COD, sulfur and ammonia. If excessive levels are reached, the condition will be alarmed in the Control Room. The plant operator will then divert the waste water flow to a holding tank until the condition is rectified.

Ammonia Stripping

Water containing some particulates and sour gases (CO_2 and H_2S) is blown down from tar separator, D-204 of the Gas Cooling and Compression Section to sour water storage tank, S-501. It is then pumped to the Ammonia Stripper where ammonia and some phenols are removed by steam stripping. Steam consumption is reduced by heating incoming feed with stripper bottoms. Overhead vapors from the Ammonia Stripper are flared while stripper bottoms are sent to the Waste Water Treatment Sub-section for further processing.



C-501	AIR BLOWER
E-501	SOUR WATER HEATER
G-501	FILTER
H-501	VIRGIN STORAGE TANK
H-502	POLYELECTROLYTE STORAGE
P-501	SCUR WATER PUMP
P-502	WASTE WATER PUMP
G-502	STRAINER

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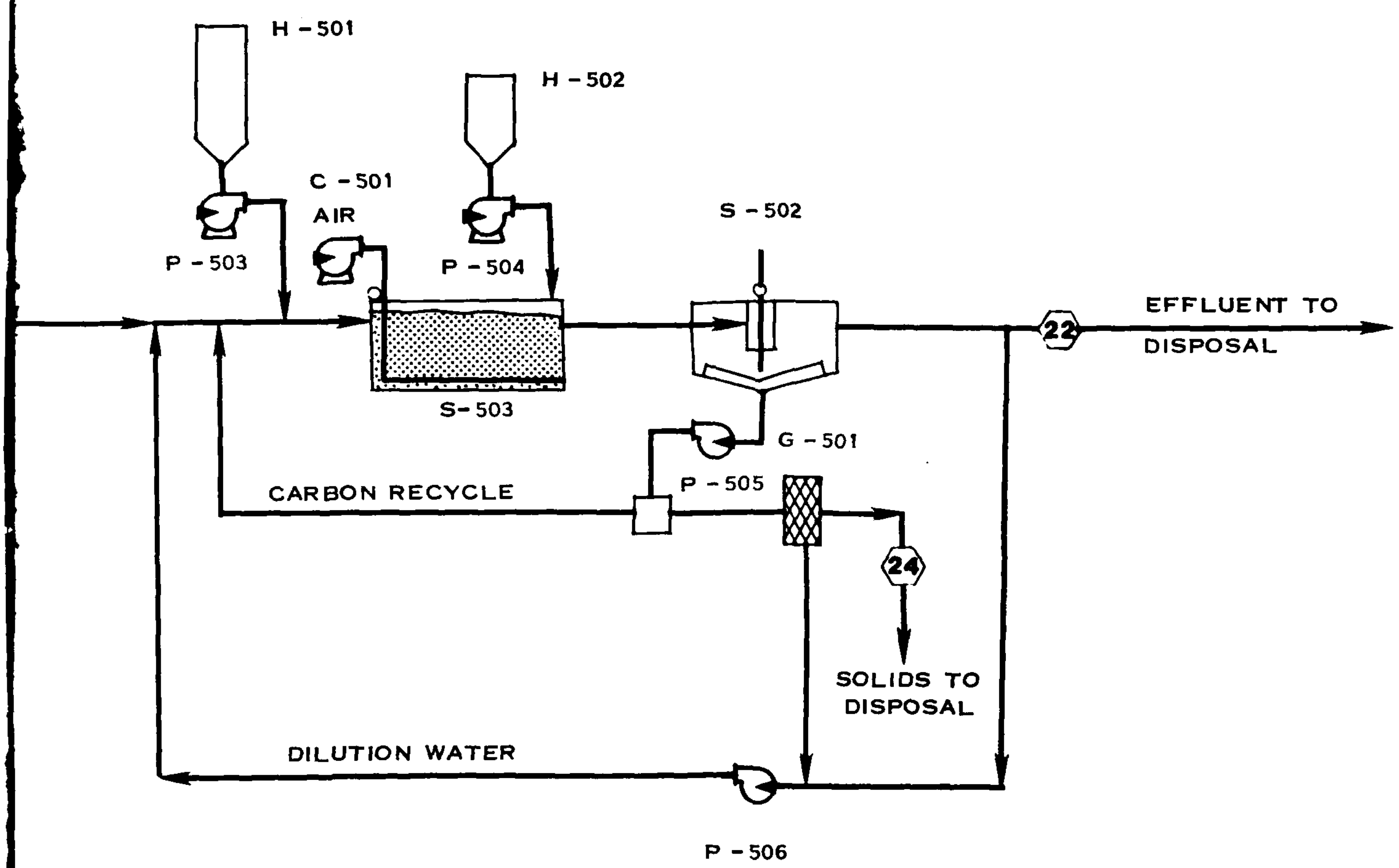

P- 503	VIRGIN CARBON FEED PUMP
P- 504	POLYELECTROLYTE STORAGE
P- 505	CARBON RECYCLE PUMP
P- 506	RECYCLE WATER PUMP
S- 501	SOUR WATER STORAGE TANK
S- 502	SETTLING TANK
S- 503	AERATION CONTACT TANK
T- 501	AMMONIA STRIPPER

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FORT GREELY, ALASKA SITE
PROCESS FLOW DIAGRAM
PROCESS CONDENSATE
TREATMENT SECTION

FIGURE 6.3-4

EBASCO SERVICES INCORPORATED

TABLE 6.3-5

MASS BALANCE - PROCESS CONDENSATE TREATMENT SECTION

Stream No.		9	21	22	23	24
Stream Name		Process Condensate Blowdown	Ammonia Flare Vent	Wastewater	Steam to Ammonia Stripper	Clarifier Waste
Components	MW	Lb Mol/hr	Lb Mol/hr	Lb Mol/hr	Lb Mol/hr	Lb Mol/hr
H_2	2.016					
CO_2	44.010	1.21	1.21			
C_2H_4	28.032					
C_2H_6	30.048					
N_2	28.016					
CH_4	16.032					
CO	18.011					
H_2S	34.080					
COS	60.070					
NH_3	17.030	0.57	0.50			
HCN	27.030					
O_2	32.000					
Ar	39.948					
H_2O (Water)	18.016	371.83	2.5	451.21	81.87	
H_2O (Steam)	18.016					
Total Flow	Lb Mol/Hr	373.61	4.21	451.21	81.87	
Total Flow	Lb/Hr	6700		8,129	1,475	166
Solids	Lb/Hr			58		
Pressure	Psia	17			40	
Temperature	oF	100			267	

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Water Treatment

Water leaving Ammonia Stripping is further treated in the Waste Water Treatment subsection. A Powdered Activated Carbon Treatment (PACT) process is used to produce a waste water adequate for discharge. Raw water entering the system is first diluted by addition of recycled effluent water to adjust the concentration of toxic substances to the requirements of the biological treatment plant. Virgin carbon from H-501 storage tank is added to the diluted waste water as it flows into the aeration contact tank S-503. In the aeration tank the waste water is aerated in the presence of activated carbon, biomass, and inert ash. Mixed liquor dissolved oxygen level is maintained to insure optimum treatment.

To aid in solids settling, polymer from H-502 storage tank is added to the mixed liquor as it flows to the system clarifier S-502. In the clarifier, the solids are settled out. The clarifier overflow is split into two streams. A portion of the clarifier overflow is discharged for disposal. No further treatment of this effluent discharge is required. The remainder of the clarifier overflow is recycled for dilution of incoming feed.

Clarifier underflow solids are continuously recycled to the aeration tank to maintain the high mixed liquor solids concentration. Spent carbon and biomass from the clarifier underflow are filtered before disposal. Filtrate water is combined with effluent recycle for dilution of feed.

6.3.3 System Performance

Each plant section is expected to meet or exceed the system availability given in paragraph 2.4 due to the following:

- The technologies used are commercially proven.
- Equipment is selected to provide continuous operation with minimum operator attention and minimum maintenance.

- The design guidelines which are used in the design of each section assure continuous, safe operation. The CO Shift Section performance is based on end of run conditions, where the performance of the catalyst is at its lowest point. But at start of run, when the bed operates with fresh catalyst, the optimum operating conditions can be maintained at lower temperatures, with lower steam consumption.

  The sulfur removal plant can remove all H_2S in the gas resulting from a coal with higher than design sulfur content by increasing the Stretford solution flowrate.

- The availability of the system is increased by providing installed spares for all the pumps in the process.

The performance of the Gas Processing System under part load conditions can be assessed as satisfactory. Variations in the gas flow rate greater than 50% turndown can be handled with no adverse effect on product quality, but with some reduction in plant efficiency for reasons indicated below.

Final cooling and cleaning of the gas is achieved by scrubbing with water. In order to maintain scrubbing effectiveness, the liquid circulation flow rate and corresponding pumping power must be sustained even though the gas flow rate is reduced.

To prevent destructive gas surging at low flows, the centrifugal compressors must bypass gas from their discharges to their inlets, increasing the compression horsepower per unit of gas processed. The extent of the increase in specific power consumption depends on the compressor selected and will be evaluated during the detail design phase.

The CO shift reactors can accept a turndown below 50% in the gas flow rate. Although the conversion rate improves with reduced space velocity it becomes more difficult to reach the design reaction temperature because reduced gas flow makes less reaction heat available for preheating the feed gas.

The Stretford process has a high degree of flexibility in that it can tolerate wide variations in both gas feed rate as well as H_2S concentration, especially, when using a venturi contactor (7) without negative impact on the energy consumption, or plant performance.

The ammonia stripping process in the Process Condensate Treating Section requires good contact between the waste water and the live steam. If the liquid flow rate is reduced by more than 30% or more the ammonia stripper can be operated intermittently at full rate, using waste water collected in the Sour Water Storage Tank.

The PACT waste water treatment system also has a high degree of flexibility and can accommodate wide variations in the composition and flow rate of the feed.[8] The addition of dilution water gives the system the ability to adjust the composition of the waste water feed to the requirements of the PACT process.

6.3.4 Maintenance

Equipment constituting the Gas Processing Section is selected and applied for maximum reliability which is sustained by a preventative maintenance program. Typical maintenance procedures most of which are applied during the annual scheduled shutdown, are as follows:

- Replacement or repacking of bearings
- Replacement or cleaning of spray nozzles
- Filter and strainer replacement
- Alignment of equipment
- Vibration tests and rebalancing of rotating apparatus if required
- Valve and steam trap servicing
- Testing, adjusting, recalibrating and/or replacement of instrumentation and controls
- Tank and vessel cleaning
- Retubing of heat exchangers
- Replacement of tower packing
- Changeout of catalysts, etc.

6.3.5 Technical Risks

The assessment of technical risks associated with this part of the plant indicates that the overall technical risks may be considered low.

The equipment and processes used for Gas Cooling and Cleaning have been used in the coke oven industry in similar applications. The venturi scrubber used for final cooling and cleaning of the gas is of the type used in existing Texaco coal gasification plants.

The gas compressor can be subject to corrosion and erosion from gas constituents. During detailed design, consideration will be given to avoiding condensation in the compressor and to the selection of suitable materials of construction.

The CO Shift section is not considered to be a high risk, as far as equipment failure and performance are concerned. The COMO sulfur tolerant catalyst, has been used successfully in the chemical industry. Currently there are two Texaco coal gasification projects (TVA and Texas-Eastman) which are using the catalyst without any indication of deterioration. The process conditions do not pose any fabrication problems, comparably sized equipment operating at similar pressures being relatively common. The economic risks associated with the catalyst utilization are not considered high, as failure would occur as a gradual reduction of activity as opposed to catastrophic failure or total inoperability. Risk would reduce the potential for the additional cost of recharging the reactors at greater frequency than expected.

Although not used extensively in coal gasification plants, the Stretford process has been used successfully in the petrochemical industry.(7) The process uses relatively simple equipment items such as a venturi scrubber and circulating pumps, which will be provided with installed spares to minimize process disruptions due to possible equipment failure. Reports from operating Stretford plants have in some cases indicated higher chemical consumption than anticipated. Although the reagents used are expensive, the cost of potentially increased consumption is small in terms of overall operating costs for this Section.

The front end process of the condensate treatment section is an Ammonia Stripping unit. Ammonia stripping is a well established process where the variations of ammonia concentration in waste water are controlled by adjusting the steam injection.

The PACT process used in the process condensate treatment is a new advanced biophysical treatment system, which is not yet fully commercialized. Extensive testing of coal gasification waste water was performed in pilot plant operations. Ammonia stripping and phenol extraction failure tests have confirmed that the PACT process provides continuous, reliable treatment, resistant to synfuels facility process upset. Experience has shown that following each organic stress test, the PACT process returned to optimum operation within 2 to 4 days.

By providing excess capacity in the activated carbon feeding system and increased contact time in the aeration tank, the PACT system can be designed to overcome the risks of process upsets.

6.3.6 References

6.3-1 Gas Engineers Handbook, The Industrial Press, 1965

6.3-2 Kinetics Technology International Corporation, "Site-Specific Assessment of a 150-MW Coal Gasification Fuel Cell Power Plant" EPRI EM-3162, November 1983

6.3-3 Kinetics Technology International Corporation, "Assessment of a Coal Gasification Fuel Cell System for Utility Application" EPRI EM-2387, May 1982

6.3-4 C F Braun & Co, "Assessment of Sulfur Removal Processes for Advanced Fuel Cell Systems" EPRI EM-1333, January 1980

6.3-5 Wellman-Galusha Gas Producers, Dravo

6.3-6 Personal Communication with Dravo Engineers, Inc.

6.3-7 Personal Communication with the Ralph M Parsons Co.

6.3-8 Personal Communication with Zimpro, Inc.

6.3-9 Personal Communication with Westinghouse.

6.4 FUEL CELL AND POWER CONDITIONER

6.4.1 Fuel Cell System

6.4.1.1 Functions and Design Requirements

The function of the fuel cell system is to take the hydrogen rich gas stream from the gas processing section, and to convert the energy value of this fuel into useable electric, mechanical and thermal energy. The fuel cell system consists of the fuel cell stacks, catalytic combustor, gas-expander, air circulator, compressor and electric-generator.

DC power is produced in the fuel cell by the electrochemical reaction of the hydrogen in the gas stream with the oxygen in the compressed air supply. Unregulated DC power is sent to the power conditioner where it is converted to three phase, 60 Hz AC power suitable for connection to the utility grid. Byproduct heat from the fuel cell is removed by a cooling system and utilized in the thermal management system. Energy remaining in the fuel cell vent gases is extracted by a catalytic combustor and an expander turbine which drives an electric-generator.

A flow diagram of the system is shown in Figure 6.4-1.

Criteria for the fuel cell is as follows:

- The fuel cell is a phosphoric acid type of modular design, manufactured by Westinghouse Electric Corporation.
- Gross DC output is 7.5 MW under design conditions.
- Electrical conversion efficiency averages 54% over the design life.
- Fuel cell stacks are replaceable and have a 40,000 hour design life.
- Oxygen is supplied to the fuel cell by compressed air.
- Fuel cell is air cooled and the byproduct heat is recovered.
- The fuel cell is capable of operating over a range of 50 to 100 percent of design DC power output.
- The fuel cell vent gas effluent meets all federal and local environmental pollution standards.

AD-A173 688 FEASIBILITY STUDY OF COAL GASIFICATION/FUEL CELL/COGENERATION PROJECT FOR..(U) EBASCO SERVICES INC NEW YORK B ROSSI ET AL. NOV 85 DAAG29-85-C-0007 2/3

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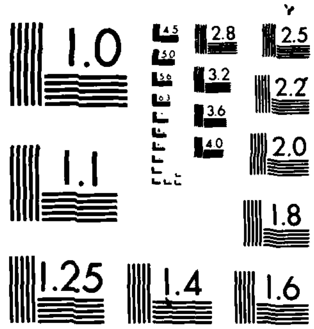

MICROCOPY RESOLUTION TEST CHART
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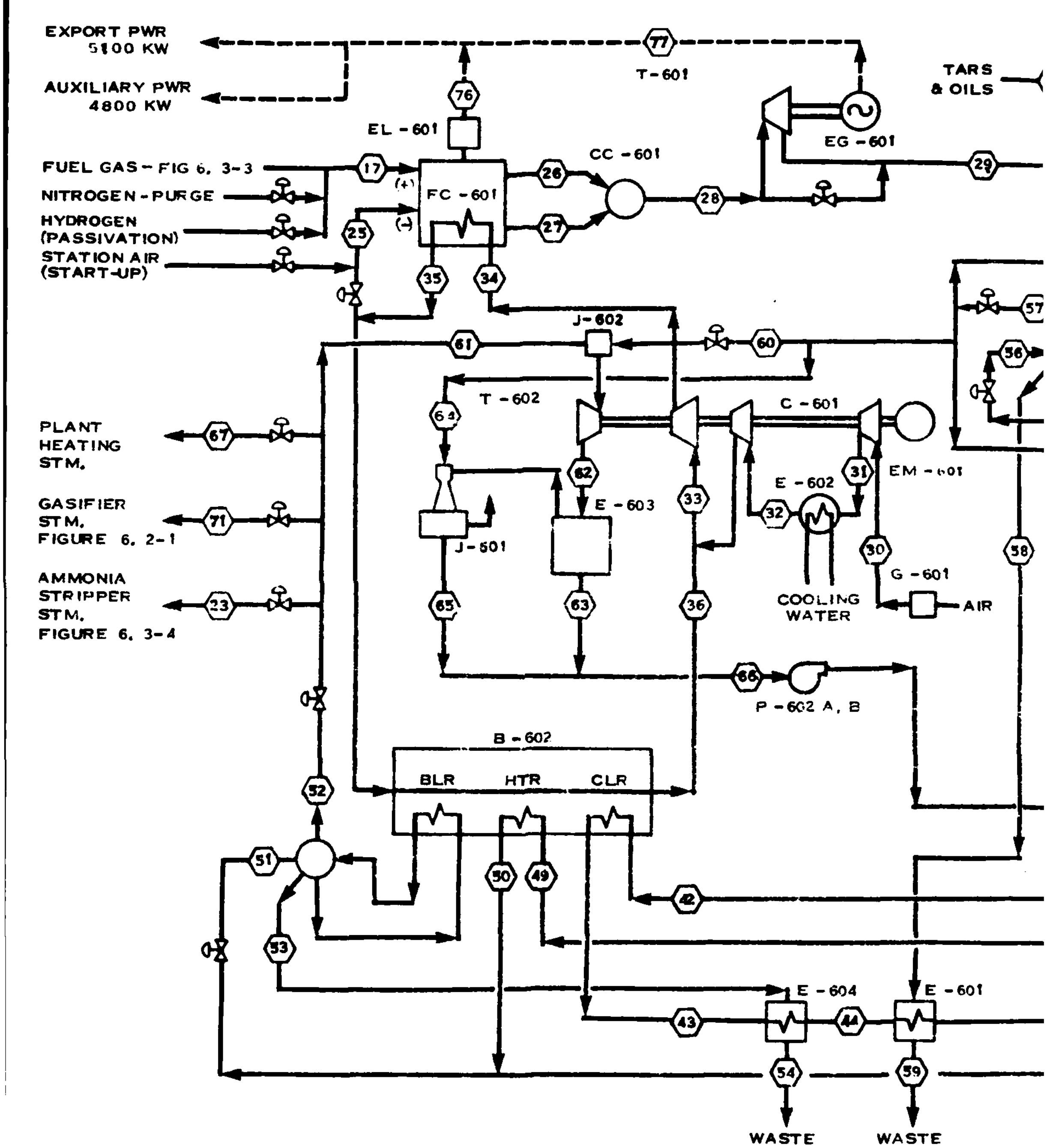
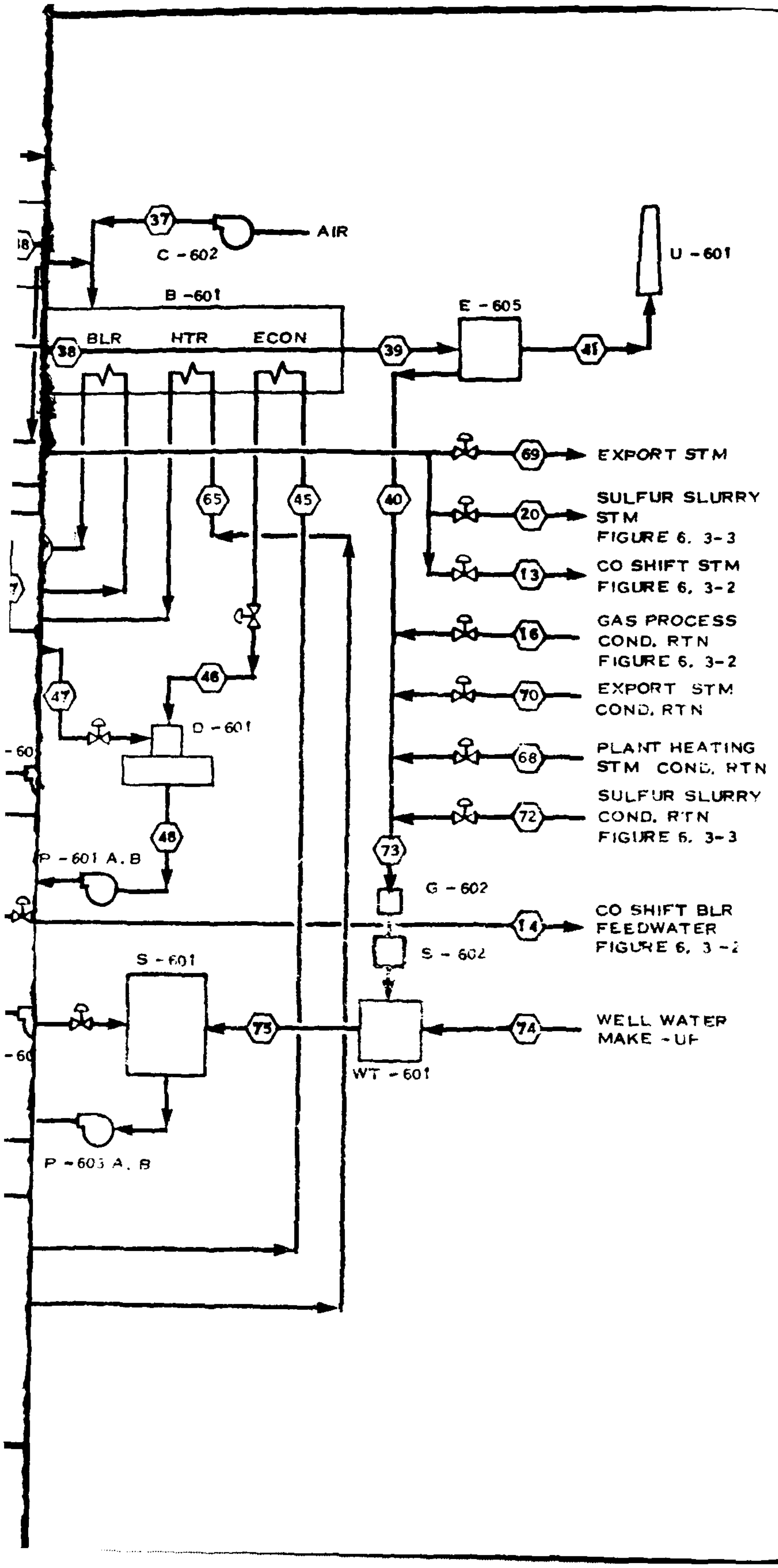

EXPORT PWR
5100 KW
AUXILIARY PWR
4800 KW
T-601
TARS
& OILS
EL-601
EG-601
CC-601
FUEL GAS - FIG 6. 3-3
NITROGEN-PURGE
HYDROGEN
(PASSIVATION)
STATION AIR
(START-UP)
FC-601
J-602
T-602
C-601
EM-601
E-602
E-603
J-601
COOLING
WATER
G-601
AIR
PLANT
HEATING
STM.
GASIFIER
STM.
FIGURE 6. 2-1
AMMONIA
STRIPPER
STM.
FIGURE 6. 3-4
P-602 A, B
B-602
BLR
HTR
CLR
E-604
E-601
WASTE
WASTE



B-601	COMBUSTOR GAS HEAT RECOVERY STEAM GENERATOR
B-602	FUEL CELL AIR HEAT RECOVERY STEAM GENERATOR
C-601	FAN
C-602	COOLING AIR CIRCULATOR
CC-601	CATALYTIC COMBUSTOR
D-610	DEAERATING HEATER
E-601	BLOWDOWN HEAT EXCHANGER
E-602	AIR COMPRESSOR INTERCOOLER
E-603	STEAM CONDENSER
E-604	BLOWDOWN HEAT EXCHANGER
E-605	AIR-COOLER
EG-601	ELECTRIC GENERATOR
EL-601	POWER CONDITIONER
FC-601	FUEL CELL
G-601	AIR FILTER/SILENCER
G-602	WATER FILTER
J-601	STEAM JET AIR EJECTOR
J-602	STEAM JET PUMP
P-601	FEEDWATER PUMP
P-602	CONDENSATE PUMP
P-603	MAKEUP WATER PUMP
S-601	CONDENSATE STORAGE TANK
S-602	CONDENSATE PRONVER TANK
T-601	GAS EXPENDER
T-602	STEAM TURBINE
U-601	VENT STACK
WT-601	MAKEUP DEMINERALIZER

DOA / GEORGETOWN UNIVERSITY

COAL GAS / FUEL CELL / COGENERATION

FORT GREELY, ALASKA SITE
PROCESS FLOW DIAGRAM
WESTINGHOUSE FUEL CELL AND
THERMAL MANAGEMENT SYSTEMS

FIGURE 6.4 - 1

EBASCO SERVICES INCORPORATED

Fuel cell performance is dependent on the characteristics of the hydrogen rich anode gas. Anode gas must meet pressure and temperature criteria set by the fuel cell manufacturer, and the purity requirements of Table 6.4-1.

6.4.1.2 System Description

The fuel cell system mass balance is given in Table 6.4-2. Fuel cell parameters are shown in Table 6.4-3. The fuel cell must be purchased from one of the two fuel cell manufacturers with designs near commercialization. The design and configuration of the fuel cell for the Georgetown site will conform to the Westinghouse design.[1]

The fuel cell anode receives hydrogen rich gas from the gas processing system. At the design power output of 7.5 MWe DC, the anode of the fuel cell requires 556 lb moles of hydrogen per hour. This results in an anode gas flow of approximately 36,600 lbs/hr of which 34.5% is hydrogen. The fuel cell utilizes 83% of the hydrogen fuel and discharges the remaining hydrogen along with the carrier gas from the anode vent. No gas other than hydrogen undergoes a reaction at the anode.

TABLE 6.4-1

ANODE FEED GAS SPECIFICATION

COMPONENT	LIMIT[1]
H_2	32% min[3]
CO	2% max
Olefins	1000 ppm max
Higher Hydrocarbons	1000 ppm max
NH_3	0.5 ppm max
Cl_2	0.5 ppm max
H_2S + COS	5 ppm max
Tars/Oils	.05 ppm max (by wt)
Metal ions	1 ppm max (by wt)
Particulates	30 ug/m^3 max
Pressure	70 psia
Temperature [2]	375°F
H_2 Flow	556 lb moles/hr

Notes:

1. By volume unless otherwise noted
2. Design temperature of cell
3. Design basis. Lower values may be acceptable but will penalize cell performance

TABLE 6.4-2

MASS BALANCE - FUEL CELL SECTION

Stream No.		17	25	26	27	28
Stream Name		Anode Inlet	Cathode Inlet	Anode Outlet	Cathode Outlet	Catalytic Combuster Outlet
Components	MW	Lb Mol/hr	Lb Mol/hr	Lb Mol/hr	Lb Mol/hr	Lb Mol/hr
H_2	2.016	556.12		94.54		
CO_4	44.010	405.51		405.51		449.32
C_2H_4	28.032	2.02		2.02		
C_2H_6	30.048	1.64		1.64		
N_2	28.016	576.98	1,723.68	576.98	1,723.68	2,300.66
CH_4	16.032	20.85		20.85		
CO	18.011	15.64		15.64		
H_2S	34.080	0.0008		0.0008		
COS	60.070	0.0006		0.0006		
NH_3	17.030					
HCN	27.030					
O_2	32.000		461.58		230.79	122.2
Ar	39.948		22.30		22.30	22.30
H_2O (Water)	18.016					
H_2O (Steam)	18.016	34.00	22.30	34.00	483.88	
SO_2	64.060					0.0014
Total Flow	Lb Mole/Hr	1,612.76	2,229.86	1,151.16	2,460.65	3,557.56
Total Flow	Lb/Hr	36,643	64,354	35,693	65,284	100,977
Pressure	Psia	70	70	65	69	65
Temperature	°F	375	365	375	378	1,096

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TABLE 6.4-2 (Cont'd)

MASS BALANCE - FUEL CELL SECTION

Stream No.		29	30	31	32	33
Stream Name		HRSG B-601 Inlet	Vent Stack	Compressor C-601 Inlet	C-601 Stage 1 Outlet	C-601 Stage 2 Inlet
Components	MW	Lb Mol/hr	Lb Mol/hr	Lb Mol/hr	Lb Mol/hr	Lb Mol/hr
H_2	2.016	-	-	-	-	-
CO_2	44.010	449.32	449.32	-	-	-
C_2H_4	28.032					
C_2H_6	30.048					
N_2	28.016	2,300.66	2,300.66	1,723.68	1,723.68	1,723.68
CH_4	16.032	-	-	-	-	-
CO	18.011	-	-	-	-	-
H_2S	34.080	-	-	-		-
COS	60.070	-	-	-	-	-
NH_3	17.030	-	-	-	-	-
HCN	27.030	-	-	-	-	-
O_2	32.000	122.20	122.20	461.58	461.58	461.58
Ar	39.948	22.30	22.30	22.30	22.30	22.30
H_2O (Water)	18.016	-	-	-	-	-
H_2O (Steam)	18.016	663.08	663.08	22.30	22.30	22.30
SO_2	64.060	0.0014	0.0014			
Total Flow	Lb Mole/Hr	3,557.56	3,557.56	2,229.86	2,229.86	2,229.86
Total Flow	Lb/Hr	100.977	100.977	64,354	64,354	64,354
Pressure	Psia	17	16	14.7	32	32
Temperature	°F	737	230	60	232	95

TABLE 6.4-2 (Cont'd)

MASS BALANCE - FUEL CELL SECTION

Stream No.		34	35	36	37
Stream Name		Circulator C-601 Inlet	Fuel Cell Cooling	Cooling Air Return	HRSG B-602 Outlet
Components	MW	Lb Mol/hr	Lb Mol/hr	Lb Mol/hr	Lb Mol/hr
H_2	2.016	-	-	-	-
CO_2	44.010	-	-	-	-
C_2H_4	28.032				
C_2H_6	30.048				
N_2	28.016	34,819.79	34,819.79	33,096.11	33,096.11
CH_4	16.032	-	-	-	-
CO	18.011	-	-	-	-
H_2S	34.080	-	-	-	-
COS	60.070	-	-	-	-
NH_3	17.030	-	-	-	-
HCN	27.030	-	-	-	-
O_2	32.000	9,324.32	9,324.32	8,862.74	8,862.74
Ar	39.948	450.45	450.45	428.15	428.15
H_2O (Water)	18.016	-	-	-	-
H_2O (Steam)	18.016	450.45	450.45	428.15	428.15
Total Flow	Lb Mole/Hr	45,045.01	45,045.01	42,815.15	42,815.15
Total Flow	Lb/Hr	1,299,999	1,299,999	1,299,999	1,235,645
Pressure	Psia	70	71	70	70
Temperature	°F	290	294	365	290

TABLE 6.4-3

FUEL CELL PARAMETERS

Parameter	Fort Greely Fuel Cell
No. of Fuel Cell Stacks	20
Stack Size	4'-6" dia x 11'-6"
Overall skid ht. (Fuel Cell Skid Only)	25' 2"
Arrangement	2 groups of 10 cell stacks arranged in 2 rows of 5 vessels each. Mounted on an elevated platform with piping below
Cell Voltage (DC)	.66V
Electrical Conversion Efficiency	54%
Line Voltage (DC)	1070V
Power Output (gross DC)	7.5MWe
Cell Operating Temp/Pres	375°F/70 psia
Design Stack Life	40,000 hours
Fuel (Anode) Input (H_2)	556 lb moles/hr
Anode Mass Flow Inlet	36,643 lbs/hr
Anode Inlet Temp	375°F
Anode Inlet Pressure	70 psia
Anode Exhaust Temp/Pres	375°F/65 psia
H_2 Utilization	83%
Cathode Inlet Flow	461.5 lb moles O_2/hr
	64,354 lbs air/hr
Cathode Inlet Temp/Pres	same as coolant outlet
Cathode Outlet Temp/Pres	378°F/69 psia

TABLE 6.4-3 (Cont'd)

Parameter	Fort Greely Fuel Cell
O_2 utilization	50%
Coolant type	air
Coolant flow	1.3×10^6 lbs/hr
Inlet Temp/Pres	294°F/71 psia
Outlet Temp/Pres	365°F/70 psia
Heat rejected to coolant	22.6×10^6 Btu/hr

Hydrogen molecules that react at the anode, give up two electrons to form two hydrogen ions. These ions migrate through the phosphoric acid electrolyte to the cathode, where they react with oxygen to form water. Oxygen is supplied to the cathode in the form of compressed air. Approximately 64,000 lbs of air flows to the fuel cell cathode. Fifty percent of the oxygen in the air is utilized in the fuel cell. The oxygen depleted air carrying water vapor formed in the fuel cell, exits at the cathode exhaust.

The efficiency and performance of the fuel cell is highly dependent upon the operating pressure and temperature. Westinghouse has designed the fuel cell to operate at 70 psia and 375°F. The pressure of the anode gas is maintained by the Gas Processing Section. The temperature of the fuel cell is maintained by the flow of cooling air through the cell stacks which carries off the heat generated in the fuel cell by the exothermic reaction of hydrogen. Under design conditions, 22.6 x 10^6 Btu/hr of heat is transferred from the fuel cell to the cooling air; this heat is recovered by the Thermal Management System. A portion of the cooling air is diverted to the cathode to provide oxygen for the electrochemcial reaction.

The fuel cell consists of 20 cell stack assemblies. Each assembly contains four stacks of 419 cells with each cell having an active cell surface area of 1.35 ft^2. Each assembly of four stacks is enclosed in a pressure vessel 11' 6" high which is mounted over manifold piping for hydrogen, air and exhaust gases. Due to the large size of the air piping, approximately 14 feet of clearance is needed under the vessels, resulting in a skid height of over 25 feet. The stack assemblies are arranged into two groups of ten, consisting of five linear pairs. Each stack assembly is connected individually to the power conditioner.

Gases exit the anode containing unreacted hydrogen along with small amounts of other hydrocarbons that were formed in the coal gasification process. The heat value of these gases is recovered by combining with the cathode exhaust and burning in a catalytic combustor. The combustor consists of a pressure vessel with a mixing manifold, a gaseous mixing chamber and a length of Pt/Pd catalyst on a ceramic or metal matrix.

A catalytic combustor was chosen because it can burn trace quantities of combustible gases without concern for flame propagation. An alternative design would be to use a flame burner, but natural gas or other fuel would have to be added to maintain the burner flame.

Under design conditions, 21.1 million Btu/hr is released in the combustor, raising the exit gas temperature to 1096°F. The hot exhaust gases are first expanded in turbine T-601 and then cooled in heat recovery steam generator B-601. The turbine drives a generator which produces 2.78 MWe ac power.

The vent gases are the only environmental emissions from the fuel cell system. Pollutants consist of SO_2, NO_x and particulates formed in the catalytic combustor. These pollutants are minimized due to the extensive scrubbing in the gas processing system and the relatively low temperature in the catalytic combustor compared to normal gas fired turbine plants. The quantity of pollutants in the vent gases are shown in Table 7-1.

Cooling air to the fuel cell is provided by an integrally connected air compressor (C-601) and circulator (C-602). Approximately 1.3 million lbs/hr of cooling air is circulated thrugh the stack assemblies in a loop with a heat recovery steam generator so that rejected heat may be recovered in the Thermal Management System. To minimize the required horsepower of the air circulator, only 1 psi pressure drop is allowed in the loop, requiring large diameter air circulation pipe.

A portion of the cooling air exiting the fuel cell is directed back to the cathode to provide oxygen for the reaction with hydrogen. A two stage air compressor provides air to the cooling loop to makeup for air diverted to the cathode. The air compressor and circulator require 2671 shaft horsepower under full load. Driving force is provided by a steam turbine in the Thermal Management System and an electric motor which is also used for startup.

6.4.1.3 Performance

The basic performance parameters of the fuel cell system are dc current, dc voltage and reactant utilization. Under design conditions, a supply of 556 lb-moles/hr of hydrogen and 461 moles of oxygen will provide 7020 amps at a stack assembly voltage of 1080 volts. These parameters will vary with the load and the age of the cell stacks.

The cell voltage, and hence the electrical conversion efficiency, will vary with the age of the cell stack due to contamination of the electrodes. Voltage will decrease slightly more than 20% over the 40,000 hour design life of the cell. The individual cells have a nominal voltage of .68 volts under design conditions when new. It is estimated that this voltage will fall .002 volt for every 1000 hours of use.

The fuel cell will normally be base loaded, but it can operate at any load between 50% and 100% of design. As load decreases, cell current density decreases and thereby increases the cell efficiency (voltage). The fuel cell operates at approximately 10% greater efficiency at 50% power.

Reactant utilization changes very little with load. A constant 50% oxygen utilization is maintained regardless of load. This is achieved by varying the air pressure at the cathode. In the Westinghouse cell technology, the phosphoric acid is not completely bound in the electrolyte substrate. This allows for easy filling or draining of the acid in the stacks, but also results in varying volume and concentration of the electrolyte as it absorbs water from the cathode stream. Figure 6.4-2 shows the operating range utilizing constant temperature but varying pressure.

6.4.1.4 Maintenance

Maintenance for the turbocompressor and generator is standard for rotating equipment with emphasis on periodic check and or replacement of bearings, lubricant, and seals.

Maintenance for the fuel cell stack, centers on replacement of the stack due to degradation of the electrodes. Replacement can be based on a set schedule of operation hours or when stack voltage drops below a minimum set point. Replacement of fuel cell stacks can be staggered or all 20 can be replaced simultaneously. Replacement need not interfere with operation since a cell stack assembly can be taken off line while the plant is operational. The optimum replacement schedule will be a function of the economic penalty for stack voltage reduction and failure probability as the stacks exceed their design lifetime.

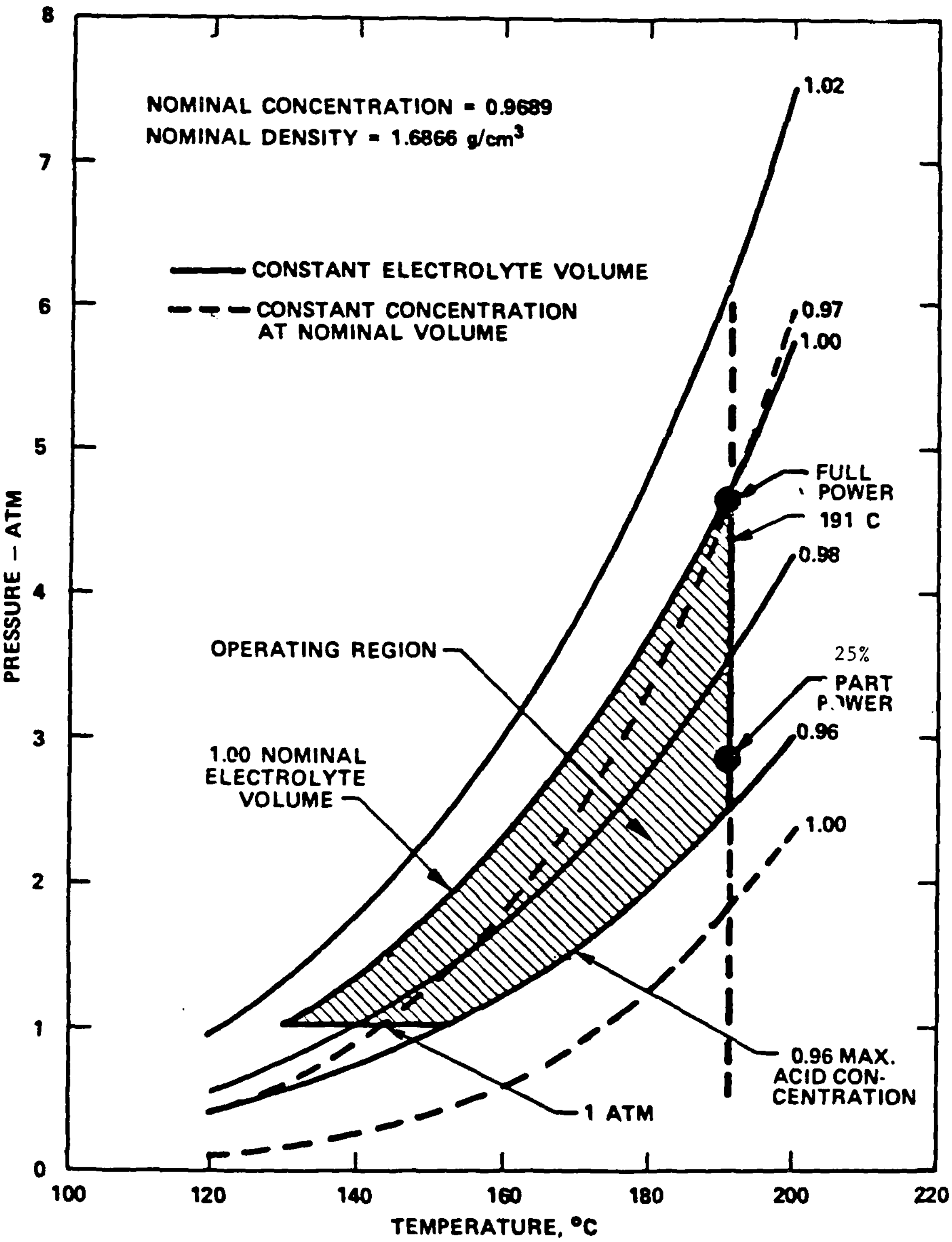


FIGURE 6.4-2 FUEL CELL OPERATING REGION FOR 50% AIR UTILIZATION

The entire stack assembly pressure vessel would be replaced and returned to the manufacturer. The catalyst bed in the catalytic combustor must also be periodically replaced.

Operation and maintenance experience on the Westinghouse cells comes mainly from laboratory testing. Westinghouse is utilizing Energy Research Corporation (ERC) cell technology which has been scaled up from smaller applications. Numerous subscale test cells have been run, some up to 40,000 hours. However, no full size stack has been tested.

Additional operational and maintenance experience is being gained from the UTC 40 kW program and the fuel cell power plant in Tokyo. Due to the differences in cell technology it is not clear how much of the UTC experience is applicable to the Westinghouse cells.

6.4.1.5 Technical Risks

Certain technical risks are inherent with the fuel cell since it is not a fully commercialized technology and operating experience is limited. Only laboratory data is available for the Westinghouse cell. Although subscale cell stacks have been constructed and the vendor has instituted a comprehensive testing program. The technical risk is that the fuel cell could fail to perform as specified due to:

- electrolyte leakage
- corrosion or mechanical failure
- low cell voltage or voltage fluctuations
- catalyst poisoning.

The first three risks can be reduced only by the cell design which in turn depends on the Westinghouse testing and development program. Earlier in the program, severe corrosion problems were encountered which forced a slippage in the commercialization schedule. The testing and development program continues, however, there is always an inherent risk of scale up problems in proceding to a full scale plant.

The plant designer can minimize the risks due to catalyst poisoning by providing clean anode gas. The anode gas clean-up provides for state of the art sulfur removal despite the fact that recent laboratory experience has indicated that this specification could be relaxed.[2]

6.4.2 Power Conditioner

6.4.2.1 Functions and Design Requirements

The power conditioner is used to convert the dc output from the fuel cell to 3-phase, ac, 60 Hz, for interconnection with the GVEA system. It also regulates the operation of the fuel cell so as to maintain the required power output. An electrical schematic diagram of a power conditioner is shown in Figure 6.4-3. The key component is the inverter which performs the conversion, maintains synchronization with the GVEA system and minimizes the generation of harmonics. The power conditioner also contains various safety elements to protect the fuel cell from abnormal voltage conditions and the conditioner itself from upset conditions.

The power conditioner and fuel cell design are linked and must be from the same vendor. The power conditioner is custom designed by Westinghouse and described in Reference 6.4-1. The system offers modular design and electrical characteristics such that it is compatible with a single 7.5 MW fuel cell. Design criteria for the power conditioner includes:

- The conditioner is rated to have an output of 7.1 MW ac.
- The conditioner is capable of operation over a range of 25% to 100% of design power output.
- Dc to ac conversion efficiency exceeds 90% over the entire operating range, and 95% under design conditions.
- The conditioner is capable of controlling both real and reactive power
- Ac output conforms to GVEA requirments

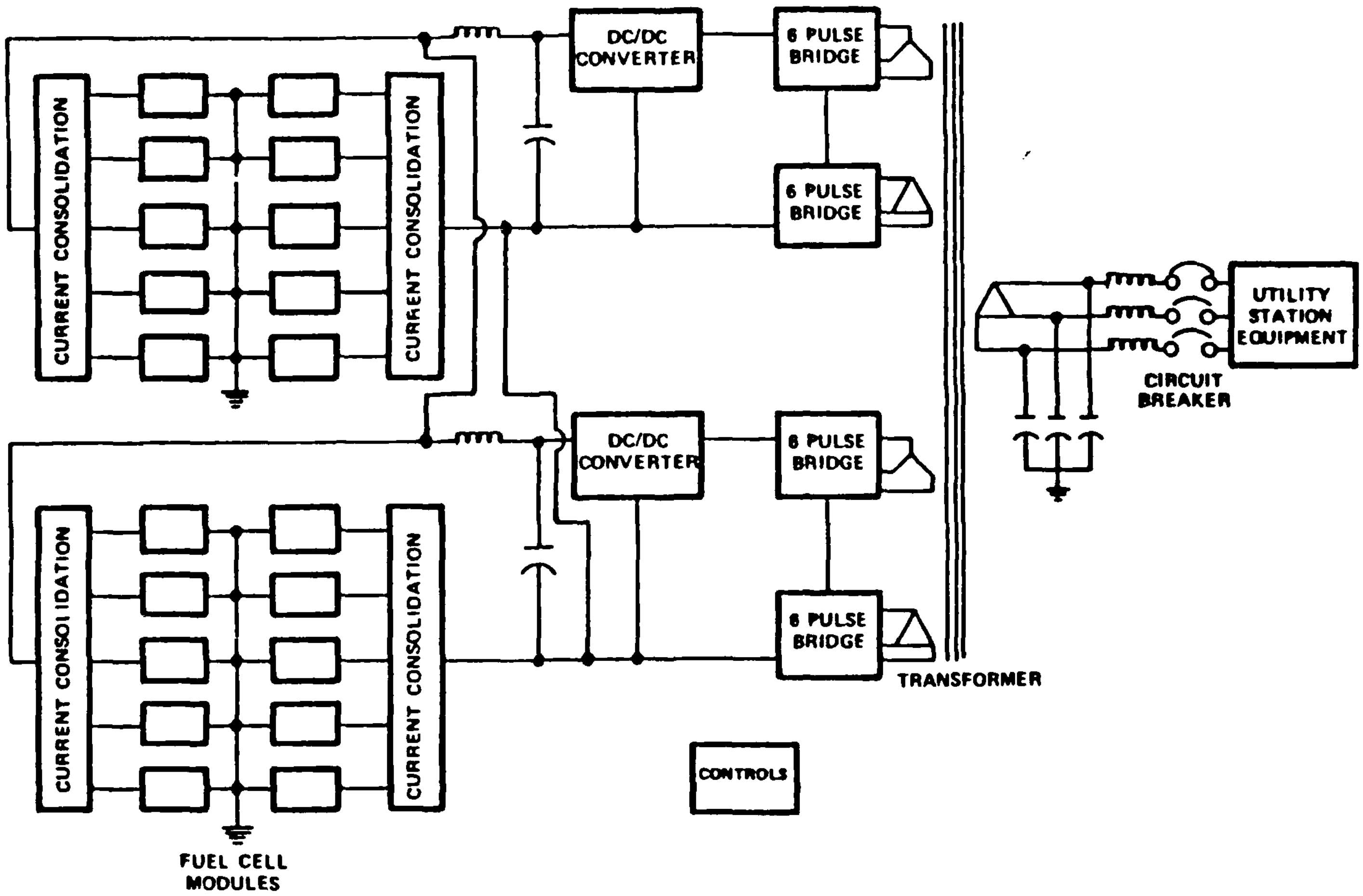


FIGURE 6.4-3 POWER CONDITIONER SCHEMATIC

6.4.2.2 System Description

The power conditioner consists of a current consolidator, dc/dc converter, dc/ac converter, output transformer, filter and ac breaker. Each of these performs a specific function as described below.

a. Current Consolidator

The consolidator circuitry compensates for unequal voltages in the fuel cell modules to allow current outputs of the modules to be combined electrically.

b. Dc/Dc Converter

The dc/dc converter is used to change the dc voltage from the consolidation circuitry to a controlled dc voltage that is applied to the dc/ac converter.

c. Dc/Ac Converter

The dc/ac converter also referred to an an inverter converts the dc output of the fuel cell to 3 phase, 60 Hz ac power. The inverter consists of two power channels for 12 pulse operation and operates over a set range of voltage and power output. All components of the inverters are static, with each inverter having six thyristor arms. Each thyristor arm consists of a series connected stack of thyristors. Thyristors are conservatively rated and each thyristor is protected against voltage and current surges. The firing circuits for the thyristors minimize the difference between the firing angles of the individual thyristors in each arm such that they equally share the blocking voltage and total voltage drop. Commutation circuits are also provided for proper functioning of the inverter. The inverter thyristors are forced cooled. The thyristor arms are modular in construction to facilitate maintenance. Thyristors shall be inverter quality and conform to Reference 6.4-3. Filters are provided for the input and output. During startup or testing the dc/ac converter can operate in the rectification mode to feed dc power back to the dc/dc converter.

d. Output Transformer

The output transformer functions to step-up the inverter ac output to a voltage suitable for interconnection to the GVEA system. The transformer is liquid-filled with natural cooling rated at 10 MVA. The transformer for a 12 pulse system is a three winding transformer with a wye connected high voltage winding. One low voltage winding is connected wye and the other delta. A no-load tap changer with 5 full capacity taps (2 above and 2 below nominal), is provided on the high voltage winding. The transformer is supplied with a liquid level indicator, liquid temperature indicator, gas detector, winding hot spot temperature detector, and sudden pressure relay.

e. Filter

The filter consists of series reactance and shunt capacitance and functions to control surges, allow for stable control of real and reactive power and reduce output harmonic content. The reactor is conservatively rated for the application and is a dry type self-cooled. The filter along with the output transformer places impedance between the inverter bridges and the ac utility line. They also buffer against utility transients.

f. Ac Breaker

The ac breaker functions to connect the converter to an ac bus. This bus may be at the facility or a GVEA bus. The breaker is a metal-clad type and may be air-magnetic or vacuum. Protective relays are to be provided as required by the GFC and GVEA, consistent with good industry practice. If the ac breaker is connected to the utility system, synchronizing equipment must be provided.

6.4.2.3 System Performance

The power conditioner converts dc current from the fuel cell to 3 phase ac power at efficiencies exceeding 90 percent over the entire operating load range of the fuel cell modules. Under design conditions of 7.5 MW gross dc, the power conditioner produces 7.1 MW ac power at a conversion efficiency of 95%. System performance is shown in Table 6.4-4. Availability is expected to exceed 90%.

Operating characteristics of the power conditioner include:

- Operator control of output levels
- automatic startup and shutdown capability
- Self-regulation of real and reactive power levels
- Self-limiting operation during abnormal ac or dc conditions
- Protection of system during out-of-limit conditions and failures.

The operator controls the mode and desired output of the power conditioner in terms of both real and reactive power levels. During automatic operation the power conditioner either attempts to maintain a preset level of output or match grid demand. The conditioner regulates the fuel cell output by sending a signal for the fuel cell controller to change the output.

The power conditioner has two operating modes and one emergency interrupt state. The operating states are: "standby", where the conditioner is armed to accept a load or go into off status; and "load", where the conditioner is fully operational. A further distinction is made between real and reactive power, where impedance is added to the circuit to produce var control. The interrupt condition refers to a situation where the utility grid is in an abnormal state in terms of voltage, current, frequency, phase or voltage.

The power conditioner is of modular design and arranged to facilitate access for removal and replacement of components or for bench repair instead of repair in the confined quarters of the cabinet. This improves the quality of maintenance and reduces the time to restore the power conditioner to service after a shutdown.

The key components are the thyristors which can easily be removed and replaced as needed. The high reliability of the system ensures that down time and maintenance are minimal.

6.4.2.4 Technical Risks

The Westinghouse power conditioner is designed specifically for fuel cell applications. Systems employing similar design concepts have proven to be reliable in utility related applications (Reference 6.4-4). One such system is the UTC power conditioner in the 4.5 MW Tokyo plant which has accumulated more than 4,500,000 kW-hours of operation with no reported problems.

Table 6.4-4 - Power Conditioner Performance Characteristics

Real Power	
Rated	7.1 MW net ac at 26.7°F ambient
Minimum	0 MW net ac (STANDBY)
Operating Range	Continuous between 25% and 100% of rated power
Factor	Unity or leading at greater than 25% power
Real Power Step Changes	
On Load	7.5%/min up; 15%/min down
From STANDBY	Under 1 h to minimum power
From COLD	Under 8 h
Power Form and Quality	
Output Voltage	Available to match standard grid voltages between 4 and 69 kV, 3-phase
Output Frequency	Nominal 60 Hz (will follow grid frequency between 61 and 57 Hz)
Harmonics	Voltage total harmonic distortion less than 5% of fundamental operating into a system with 250 MVA short circuit capacity
Voltage Imbalance and Range	Deliver rated power at 2% line-to-line unbalance ± 5% voltage range at rated power (from nominal) +10%, -20% voltage range at reduced power

6.4.3 References

6.4-1 Westinghouse Electric Corp, "Phosphoric Acid Fuel Cell 7.5 MWe dc Electric Power Plant Conceptual Design Report", WAESD TR-83-1002, May 1983

6.4-2 P. N. Ross, "The Effect of H_2S and COS in the Fuel Gas on the Performance of Ambient Pressure Phosphoric Acid Fuel Cells". Lawrence Berkeley Laboratory Report No. LBL-18001 April 1985

6.4-3 ANSI C34.2-1968 (R1973), Practices and Requirements for Semiconductor Power Rectifiers.

6.4-4 Ebasco Report PCC-HVDC-001, High Voltage Direct Current (HVDC) Reliability Study, February 13, 1984.

6.5 THERMAL MANAGEMENT SYSTEM

6.5.1 Functions and Design Requirements

Functions

The purpose of the Thermal Management System (TMS) is to convert the thermal and chemical energy flows discharged from the fuel cell and also contained in tars and oils produced in coal gasification into one or more of the following energy forms that can reduce plant operating costs or generate revenue:

1. Steam, hot water and electric power to satisfy the GFC system process demands, thereby lowering plant operating costs, improving plant overall efficiency and minimizing the need to import this energy.

2. Steam for the Ft Greely Main Post heat distribution system

3. Electric power for use by Fort Greely, Fort Wainright and/or sale to GVEA.

Design Requirements

TMS design requirements are based on interfacing with the following configuration of fuel cell and auxiliary equipment: (1) Westinghouse 7.5 MWe fuel cell (FC-601), cooled by recirculated compressed air which supplies fuel cell cathode oxygen requirements and passes through a heating recovery steam generator (HRSG) for the production of thermal energy; and, (2) HRSG thermal energy recovery of catalytically combusted fuel cell anode and cathode vent gases which have been expanded through a gas expander-electric generator set.

At 100% load, the TMS receives a fuel cell cooling air heat load of 22.5 x 10^6 Btu/hr conveyed by 1,236,000 lb/hr of 70 psia, 365 F air which is cooled by the TMS to 290 F. Fuel cell anode and cathode exhaust gases, after catalytic combustion (CC-601) and gas expansion (T-601), is

discharged to the TMS at full load conditions of 101,000 lb/hr, 17 psia and 737F. Properties of this gas mixture include a molecular weight of 28.38 and specific heat of 0.287 Btu/lb-F. This gas enters the TMS where it is increased in temperature by mixing with hot gases produced from the combustion of 837 lb/hr oils and tars, having an energy value of 15.7 x 10^6 Btu/hr, generated from coal gasification.

The TMS is designed to meet the following plant process steam, hot water, electric power and export steam requirements:

1. process steam, feedwater heating and power demands, including
   - CO shift boiler steam
   - ammonia stripper steam
   - coal gasifier steam
   - sulfur recovery heating steam
   - space heating steam
   - CO shift boiler feedwater
   - auxiliary electric power

2. process steam and water inputs including
   - CO shift condensate
   - sulfur recovery condensate
   - space heating condensate return

3. export steam to Ft Greely to satisfy year round space heating and domestic hot water heating steam requirements, but at least sufficient for compliance with the PURPA requirement that the useful thermal energy output of a qualifying topping cycle cogeneration facility be no less than 5% of the total energy output during any calendar year.

4. export electric power to the electric utility grid.

The above process and Ft Greely requirements are listed in Table 6.5-1.

Ft Greely's average monthly steam demand rang... from about 16,000 lb/hr in summer to 39,000 lb/hr in winter with steam supplied to the Ft Greely steam distribution piping system at 75 psia.

The TMS recovers thermal energy from fuel cell cooling air and from catalytically combusted fuel cell exhaust gases utilizing heat recovery steam generators which, after satisying GFC process, and plant heating requirements, has an available average steam capacity of 31,600 lb/hr.

Of this amount, 13,800 lb/hr of 120 psia steam is exported to the main post heat distribution system and 11,800 lb/hr of 40 psia steam is expanded through a helper turbine of the condensing type which in tandem with an electric motor drives the cathode air compressor and cooling air circulator. This helper turbine makes available an additional 300 kW of GFC electrical power output.

TMS equipment is designed for the following expected operating modes:

Mode	Equipment Status
Normal Load	Fuel cell at 100% power; Normal process and export steam loads
Maximum Load	Fuel cell at 100% power; Minimum process and export steam load for domestic hot water heating only
Half Load	Fuel cell at 50% load
Gas Expander/ Generator Out of Service	Fuel cell at 100% load

6.5.2 System Description

The primary energy output of the fuel cell is the net 7.1 MW electric AC power produced by the fuel cell power conditioner (EL-601). However, the fuel cell also discharges additional significant energy flows in the form of (1) thermal energy discharged to the fuel cell cooling air system and (2) chemical, pressure and thermal energies vented at the fuel cell anode (fuel gas) and cathode (air). The Thermal Management System receives these additional energy flows and converts them to useful thermal, mechanical and electric power supplies that are distributed to meet plant process needs, reducing plant operating expenses, or are exported to generate revenue.

TMS process flow diagram and stream parameters are given in Figure 6.4-1. After satisfying process thermal loads given in Table 6.5-1 approximately 13,800 lb/hr of 120 psia steam is exported to Ft Greely. TMS equipment is described in Appendix A. Refer to Table 6.5-2 for stream flows and conditions.

The TMS, as shown Figure 6.4-1, consists of the following major functional areas: fuel cell cooling air HRSG; gas expander exhaust gas HRSG; steam distribution piping; condensing steam turbine and condenser; and condensate storage. These functions are described below:

Heat Recovery Steam Generator (Fuel Cell Cooling Air)

The fuel cell cooling air system removes heat released by the fuel cell electro-chemical reaction by the forced circulation of cooling air through the fuel cell stacks. Exiting the fuel cell at 365 F, about 5% of the cooling air supplies the oxygen requirements of the cathode. The remainder of air is cooled in heat recovery steam generator B-602. Air exiting at 290 F combines with makeup air from compressor C-601, enters circulator C-602 and returns to the fuel cell. HRSG B-602 includes a boiler section, a process feedwater heater, and an economizer section. Steam flow at full load is approximately 19,000 lb/hr. Steam is discharged to TMS steam piping via a pressure control valve which maintains a constant steam drum saturation pressure/temperature of 50 psia/281°F. In case of control valve failure a safety valve protects the boiler from over pressure.

TABLE 6.5-1

TMS PROCESS CRITERIA

I. Processing Steam Requirements

A. Process Steam

CO Shift Boiler	- 12,090 lb/hr, 120 psia, 341°F
Sulfur Slurry Heating	- 110 lb/hr, 65 psia, 298°F
Gasifier Steam	- 2,195 lb/hr, 25 psia, 240°F
Ammonia Stripper	- 1,475 lb/hr, 25 psia, 240°F

B. Process Feedwater

CO Shift Boiler	- 1,770 lb/hr, 120 psia, 237°F

C. Process Condensate Return

CO Shift	- 3,452 lb/hr, 80 psia, 120°F
Sulfur Slurry	- 80 lb/hr

D. Plant Space Heating - Annual Average Demand 3,460 lb/hr @ 40 psia

TABLE 6.5-1 (Cont'd)

II. Fort Greely Steam Demand

	Space Heating lb/hr @ 60 psig	Hot Water Heating lb/hr @ 60 psig	Total lb/hr
January	24,890	13,110	38,000
February	26,210	13,110	39,320
March	15,350	13,110	28,410
April	12,910	13,110	26,020
May	7,140	13,110	20,250
June	3,030	13,110	16,140
July	3,040	13,110	16,150
August	5,190	13,110	18,300
September	7,780	13,110	20,890
October	15,450	13,110	28,560
November	23,860	13,110	36,920
December	24,470	13,110	37,580
Peak @ -48°F	41,890	13,110	55,000
Peak @ -55°F	43,790	13,110	56,900
Monthly Average	14,030	13,110	27,140

TABLE 6.5-2

MASS BALANCE - THERMAL MANAGEMENT SYSTEM

Stream No.		37	38*	39	40	41
Stream Name		Combustion Air	HRSG Heated Gas	HRSG Exit Gas	Air Cooler Condensate	Air Cooler Exit Gas
Components	MW					
CO_2	44.010		512.09	512.09		512.09
N_2	28.016	343.22	2,644.04	2,644.04		2,644.04
O_2	32.000	91.92	134.19	134.19		134.19
Ar	39.948	4.41	26.71	26.71		26.71
H_2O (Steam)	18.016	4.41	704.33	704.33	495.2	209.1
SO_2	64.06		0.06	0.06		0.06
Total Flow	lb mole/hr	443.96	4,021.42	4,021.42	495.2	3,526.22
Total Flow	lb/hr	12,814	114,669	114,669	8,914	105,755
Pressure	psia	17	17	16	15	15
Temperature	°F	60	1133	221	100	100

*Stream 38 includes the combustion in 15% excess air (stream 37) of 878 lb/hr oils and tars having a heating value of 17,880 Btu/lb and ultimate analysis of 85.79% C, 8.46% H, 4.82% O, 0.52% N, 0.22% S and 0.19% ash.

TABLE 6.5-2 (Cont'd)

Stream No.		42	43	44	45	46
Stream Name		Makeup to FC HRSG	FC HRSG Outlet Water	Blowdown HE Outlet Water	HRSG Econ. Inlet Water	Deaerator Makeup
Flow	Lb/Hr	49,149	49,149	49,149	49,149	49,149
Pressure	Psia	101	91	86	76	31
Temperature	oF	100	157	159	165	217
Enthalpy	Btu/Lb	68	125	127	133	185

Stream No.		47	48	49	50	51
Stream Name		Deaerator Steam	Deaerator Condensate	FC HRSG Htr FW In	FC HRSG Htr FW Out	FC HRSG Boiler FW
Flow	Lb/Hr	1,277	28,752	28,752	28,752	19,904
Pressure	Psia	120	26	205	195	50
Temperature	oF	343	242	242	281	281
Enthalpy	Btu/Lb	1192	211	211	250	250

TABLE 6.5-2 (Cont'd)

Stream No.		52	53	54	55	56
Stream Name		FC HRSG Steam	FC HRSG Blowdown	Blowdown HE Drain	HRSG Htr FW in	HRSG Boiler FW
Flow	Lb/Hr	18,957	947	947	28,752	28,752
Pressure	Psia	50	50	45	185	130
Temperature	oF	281	281	167	281	347
Enthalpy	Btu/Lb	1174	250	135	250	319

Stream No.		57	58	59	60	61
Stream Name		HRSG Steam	HRSG Blowdown	Blowdown HE Drain	Turbine HP Steam	Turbine LP Steam
Flow	Lb/Hr	27,383	1,369	1,369	0	11,827
Pressure	Psia	130	130	120	120	40
Temperature	oF	347	347	169	343	276
Enthalpy	Btu/Lb	1192	319	137	1192	1174

TABLE 6.5-2 (Cont'd)

Stream No.		62	63	64	65	66
Stream Name		Turbine Exh. Steam	Condenser Condensate	S.J.A.E. Steam	S.J.A.E. Condensate	Condensate Pump Inlet
Flow	Lb/Hr	11,827	11,827	160	160	11,987
Pressure	Psia	2.5 in Hga	2.5 in Hga	120	2.5 in Hga	2.5 in Hga
Temperature	oF	109	109	343	109	109
Enthalpy	Btu/Lb	1084	77	1192	77	77

Stream No.		67	68	69	70	71
Stream Name		GFC Plant Htg Steam	GFC Plant Condensate	Ft Greely Steam	Ft Greely Condensate	Gasifier Steam
Flow	Lb/Hr	3,460	3,460	13,776	13,607	2,195
Pressure	Psia	40		120		40
Temperature	oF	276		343		276
Enthalpy	Btu/Lb	1174		1192		1174

TABLE 6.5-2 (Cont'd)

Stream No.		72	73	74	75
Stream Name		Sulfur Slurry Cond	Condensate Return	Well Water Makeup	Condensate Makeup
Flow	Lb/Hr	80	33,682	3,480	37,162
Pressure	Psia				
Temperature	oF				
Enthalpy	Btu/Lb				

Stream No.		76	77
Stream Name		Power Conditioner	Generator EG-601
Flow	Lb/Hr		
Pressure	Psia		
Temperature	oF		
Enthalpy	Btu/Lb		
Power	MW	7.1	2.78
Volts	V		

A portion of steam drum water, equal to five (5) percent of the steaming rate, is discharged from the system as blowdown via blowdown heat exchanger E-604.

Heat Recovery Steam Generator (Fuel Cell Vent Gases)

High temperature exhaust gas at 737°F and 65 psia, from gas expander T-601 is used to generate high pressure steam in generator B-601 for process use and for export. The HRSG boiler section, operating at 130 psia and 347°F, generates a steam flow of approximately 27,400 lb/hr. Boiler blowdown water equals 5% of the steaming rate and, after preheating process makeup water in blowdown heat exhanger E-601, is discharged to waste treatment.

Makeup water to meet coal gas processing and TMS boiler feedwater requirements is pumped by one of two full capacity feedwater pumps (P-601A, B) from deaerating heater D-601. Utilizing boiler steam, the direct contact deaerating heater raises the entering condensate temperature to 240°F saturation temperature at 25 psia while scrubbing the water of non-condensable gases which are vented. The deaerating heater has a condensate storage volume of at least 10 minutes to assure a continued supply of boiler feedwater in case the flow of entering makeup water is interrupted. Deaerator makeup water from condensate storage tank (S-601) is pumped (P-603 A,B) through the economizer section of the HRSG B-602 where it is heated to within 25°F of deaerator saturation temperature.

P-601 pumps feedwater to the CO shift boiler of the gas processing system and to HRSG B-601 and HRSG B-602. The total HRSG feedwater flow passes through the feedwater preheat section of HRSG B-602 which increases the makeup water temperature to 281°F. Seventy percent of the flow then enters the boiler circulating loop of HRSG B-602 and the remainder flows to the preheater and boiler sections of HRSG B-601.

Gas exiting HRSG B-601 is cooled from 221°F to 100°F via air-cooler E-605. Lowering the gas temperature reduces the gas water vapor content from 17 to 6% thereby reducing the amount of water vapor discharged to the environment as well as minimizing the amount of city water makeup required for plant operation. (Air cooler E-605 is assumed to discharge its air to atmosphere. However, future studies should consider the recovery of heat from this discharge air, e.g., for spacing heating).

Gas exiting air cooler E-605 discharges to the environment through vent stack U-601. Stack height is sufficient for plume dispersion.

Steam Distribution Piping

Total TMS boiler steam flow produced in gas expander exhaust gas HRSG B-601 is about 27,400 lb/hr which is piped at 120 psia to various process steam users including CO shift, sulfur recovery, steam jet air ejector and deaerator (D-601) heating. After satisfying these loads (see Table 6.5-1) the remaining steam flow of 13,800 lb/hr is exported to the Main Post steam distribution system.

TMS boiler steam flow of 19,000 lb/hr produced in fuel cell cooling air HRSG B-602, is distributed at 40 psia to supply GFC coal gasifier, ammonia stripper and the GFC plant heating system. The remaining 11,800 lb/hr, is piped at 40 psia via steam jet pump J-602, to condensing steam turbine drive T-602. The jet pump boosts the steam turbine throttle pressure above 40 psia in the event excess 120 psia HRSG B-601 boiler steam is available during periods of low CO shift steam or export steam demand.

The steam pressure to each of the process steam loads is regulated by a pressure control device at the point of use.

Steam Turbine Generator/Condenser

During normal operation, about 11,800 lb/hr steam at 40 psia is expanded through a multi-stage steam turbine (T-602) which delivers about 420 hp to drive, with EM-601, air compressor C-601.

Due to the variability in demand of such steam users as GFC space heating, ammonia stripper and sulfur slurry heating, and perhaps a 10% lower CO shift steam load due to variations in coal gas composition, the turbine generator is designed for 170% of normal steam flow or 20,000 lb/hr. The corresponding shaft power output rating is 700 hp.

Turbine exhaust steam is condensed in a two pass single pressure condenser (E-603) which achieves a turbine exhaust pressure of 2.5 in. Hga at rated steam flow when cooled by 2,100 gpm of 60% ethylene glycol water solution at 50°F. The condenser also receives miscellaneous TMS condensate drains (except blowdown) and steam vents. Condenser tubes are 90/10 copper nickel. The condenser hotwell provides a minimum of 5 minutes of condensate storage. One of (2) 100% condensate pumps (P-602A, B) return the condensate to a condensate storage tank (S-601).

Non-condensable gases are evacuated from the condenser by a two-stage steam jet air ejector, (J-601). Condensed ejector steam is discharged to the suction of the condensate pumps.

Condensate Storage

Condensate makeup to TMS equipment is stored in a condensate storage tank (S-601) which receives about 12,000 lb/hr from the condensate pumps (P-602) and 37,200 lb/hr from water treatment system (WT-601) consisting of process and export condensate returns plus about 3,500 lb/hr city water makeup which compensates for steam and condensate consumed in process operations.

Condensate storage tank minimum storage volume equals 12 hours of full load operation without city water makeup and no condensate return from air cooler E-605.

One of (2) 100% capacity makeup water pumps (P-603A, B) supply condensate to HRSG B-602 economizer inlet. Makeup water flow is regulated based on deaerator (D-601) water level.

6.5.3 Performance

TMS HRSG boilers are designed to produce steam at 130 psia/347°F and 50 psia/281°F over the 50-100% normal operating range. Full load performance is shown on process flow diagram Figure 6.5-1.

Fuel cell waste heat rejected to the cooling air system is a function of the fuel cell power conditioner load setpoint and corresponding fuel cell efficiency. Since fuel cell efficiency increases as load decreases (fuel cell stacks operate at approximately 10% higher efficiency at 50% than at 100% load), waste heat tends to drop more rapidly than does fuel cell power output. For example, at 50% GFC plant load, based on an increase in fuel cell efficiency from 50% at full load to 60% at half load, it is estimated that the waste heat load will be 40% of full load output, causing a corresponding part reduction in the generation of steam and hot water energy generated by HRSG B-602 at part load.

However, the converse is true for catalytic combustor exhaust gas HRSG B-601 where steam production reduces at a rate that is less than the decrease in fuel cell power. For example, assuming that HRSG inlet gas flow is proportional to fuel cell load but temperature remains constant, at 50% load HRGS steam generator will be approximately 52% of full load output. Gas temperature approach to steam saturation temperature is about 1°F (based on a 25°F design pinch point temperature) indicating that nearly all of the HRSG evaporation section heat transfer surface area is utilized for steam production.

In addition to normal operation between 50 to 100% load, the TMS can operate during abnormal operation such as if gas expander T-601 is out of service. In this case full load fuel cell operation can be maintained, but with some reduction in HRSG B-601 steam production. Catalytic

combustion exhaust gas flow, at 1096°F, bypasses gas expander T-601 and discharges directly to HRSG B-601. The high gas temperature, being slightly cooler than normal operating temperature, eliminates the need for oil and tar supplemental firing. However, steam flow production decreases to about 95% of full load.

The shaft power output of condensing turbine-generator EG-602 depends (1) on the throttle steam flow available from fuel cell cooling and HRSG boiler drum outputs after the various process and export steam demands are satisfied and (2) the throttle pressure and enthalpy produced by jet pump J-602. The turbine, generator, steam condenser E-603 and condensate pumps P-602A, B, are sized for 170% of normal expected load.

6.5.4 Maintenance

Equipment constituting the TMS is of proven reliability which is sustained during the plant life by well established maintenance procedures, most of which are applied during the annual scheduled shutdown.

Included among these procedures are inspection and replacement (or plugging) of HRSG and steam condenser tubes, relubrication or replacement of bearings shaft seal replacement, coupling realignment, valve and damper maintenance, calibration and adjustment of controls, including turbine governor, vibration check and rotor balancing, replacement of cooling tower fill, etc.

6.5.5 Technical Risks

Because the TMS utilizes proven equipment, there are no technical risks beyond those normally assumed by commercial ventures in mature technologies.

6.6 Auxiliary Systems

6.6.1 Electrical

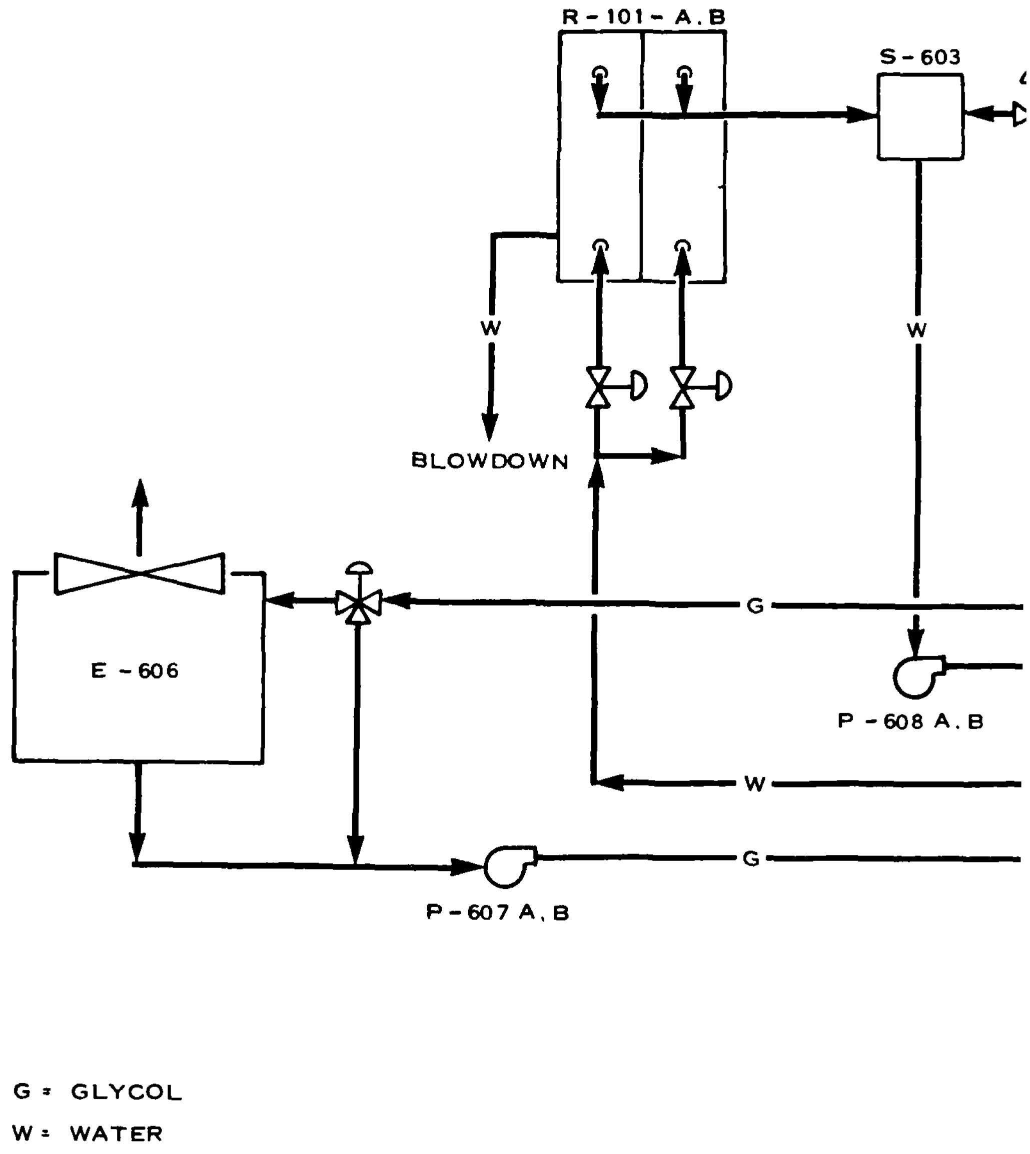
Electrical power for auxiliaries including lighting, is provided by an auxiliary power transformer. This may be a dry-type or liquid-filled transformer with natural cooling (e.g., OA or AA). The low voltage winding shall be suitably rated for the electrical auxiliaries (preferably 480 Vac, 30 60Hz). Additional dry-type transformer will be provided for 208Y/120 Vac. Auxiliary loads will be supplied by a variety of devices (e.g, metal-enclosed switchgear, motor control centers and panelboards) as required by the load. In addition, an uninterruptible power supply (UPS) will be provided for critical loads, control and instrumentation. The UPS shall consist of an inverter (with ac and dc inputs), a battery and battery charger. Alternately, some critical loads may be supplied directly from the battery.

A grounding and lightning protection system is provided. These systems conform to the requirements of IEEE and NFPA.

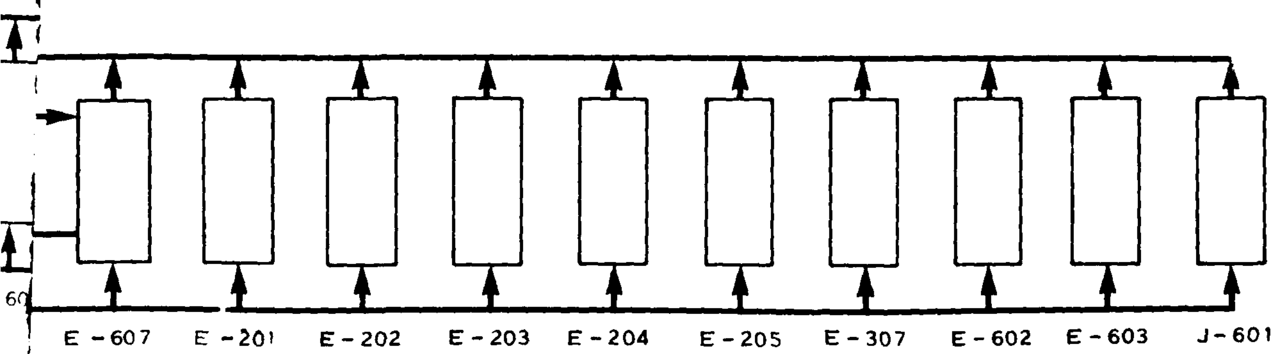
6.6.2 Cooling System

The cooling system disposes of heat rejected from the coal gasifiers and from various points in the Gas Processing and Thermal Management systems. Extreme winter temperatures make it necessary to use glycol solution and fan coolers instead of cooling towers. Referring to Figure 6.6-1, heat is transferred to the glycol in shell and tube heat exchangers and carried to the fan coolers where it is rejected to the atmosphere. Since water is required for cooling of the gasifier and as a reactant in the gasification process, a separate cooling water loop is provided which rejects gasifier heat to a glycol system heat exchanger. The total cooling load is estimated at 30 million Btu/hr.

Cooling loads for individual users are listed in Table 6.6-1:


R-101-A.B
S-603
W
BLOWDOWN
E-606
G
P-608 A.B
W
G
P-607 A,B
G = GLYCOL
W = WATER

E - 201	PRIMARY COOLER HEAT EXCHANGER
E - 202	GAS COMPRESSOR 1ST STAGE INTERCOOLER
E - 203	GAS COMPRESSOR 2ND STAGE INTERCOOLER
E - 204	GAS COMPRESSOR 3RD STAGE INTERCOOLER
E - 205	AMMONIA SCRUBBER COOLER
E - 307	CO SHIFT TRIM COOLER
E - 602	AIR COMPRESSOR INTERCOOLER
E - 603	STEAM CONDENSER
E - 606	GLYCOL/AIR COOLER
E - 607	GASIFIER COOLING WATER HX
J - 601	STEAM JET AIR EJECTOR CONDENSER
P - 607	COOLING WATER PUMP
P - 608	GASIFIER COOLING WATER PUMP
R - 101	GASIFIERS
S - 603	OVERFLOW TANK



DOA / GEORGETOWN UNIVERSITY

COAL GAS / FUEL CELL / COGENERATION

FORT GREELY, ALASKA SITE

PROCESS FLOW DIAGRAM

COOLING SYSTEM

FIGURE 6.6-1

EBASCO SERVICES INCORPORATED

TABLE 6.6-1

COOLING SYSTEM LOADS

Equipment	Designation	Heat Load (10^6 Btu/hr)
Coal Gasification		
Coal Gasifiers	R-101	2.51
Gas Cooling Cleaning and Compression		
Gas Compressor 1st Stage Intercooler	E-202	1.68
Gas Compressor 2nd Stage Intercooler	E-203	1.01
Gas Compressor 3rd Stage	E-204	.73
Ammonia Scrubber Cooler	E-205	.09
CO Shift		
Trim Cooler	E-307	.5
Thermal Management		
Air Compressor Intercooler	E-602	2.1
Steam Turbine Condenser	E-603	20.15
SJAE Condenser	J-601	.2
Miscellaneous Coolers		1.03

Major components of the cooling water system are the fan coolers, glycol pumps and piping.

The fan coolers are glycol to air heat exchangers providing 110°F cold glycol at 75°F dry bulb air design temperature. Air flow through the coolers is maintained by 2 speed propeller fans totalling 170 hp. Fans are sequenced and cycled with damper and glycol bypass controls based on outdoor temperatures and plant load.

Each of two 100% capacity glycol pumps delivers approximately 3800 gpm of cooling water at 120 feet total head and is driven by a 200 HP electric motor. Two 100% capacity cooling water pumps are also provided for the gasifier cooling water loop. Each pump delivers 80 gpm at 60 feet head and is driven by a 3 hp motor.

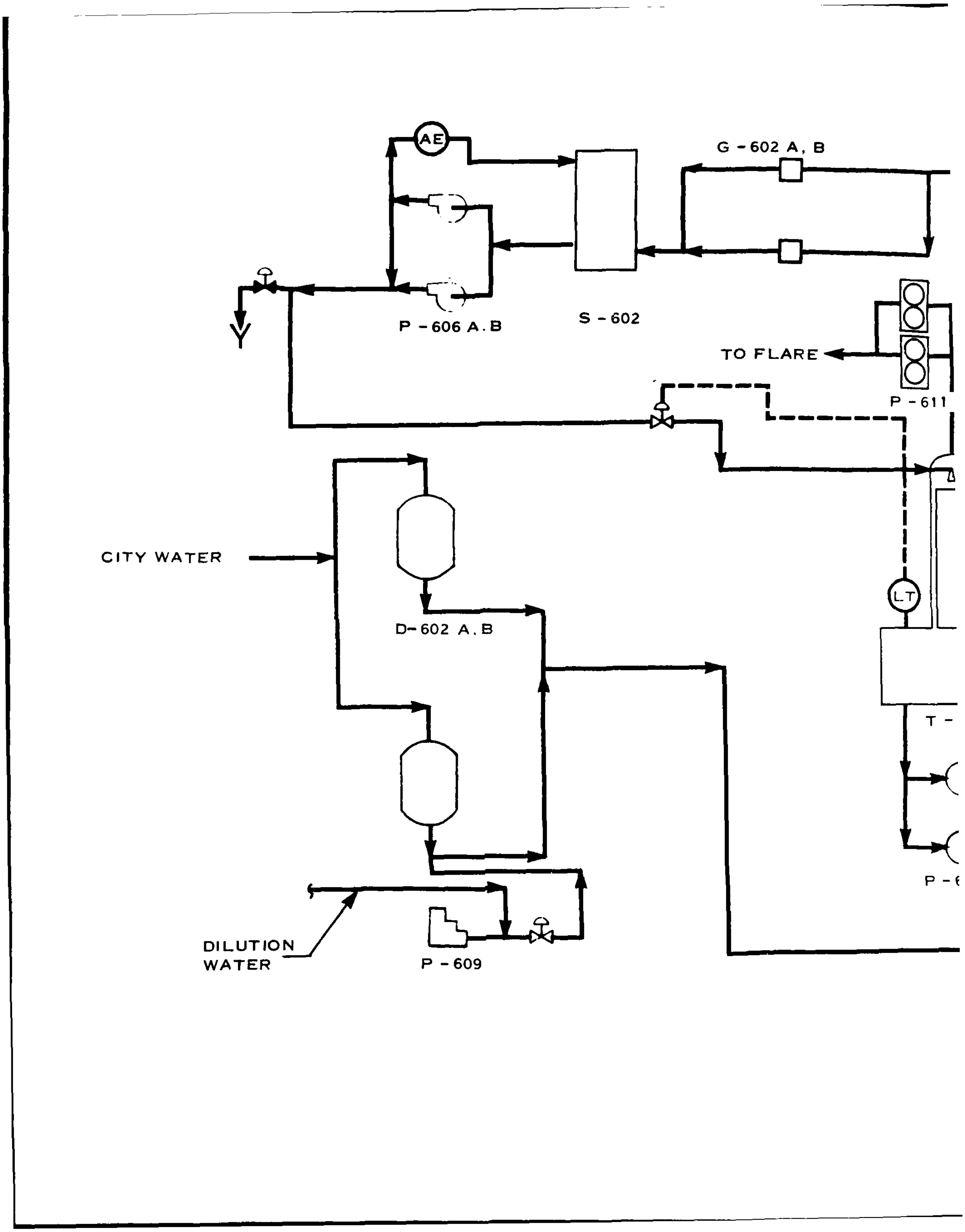
6.6.3 Water Treatment

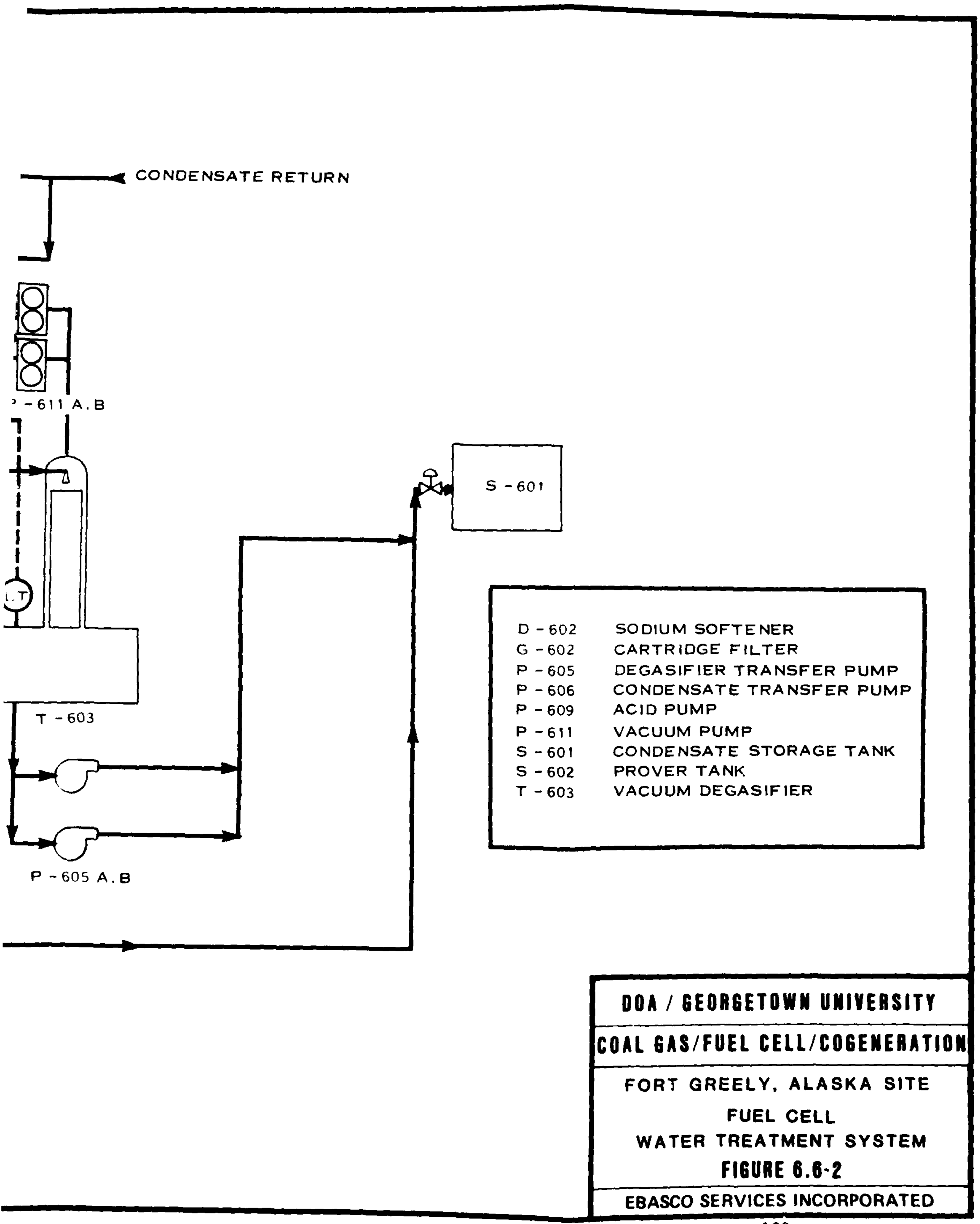
The Makeup Water Treatment System shown in Figure 6.6-2 will process well water to produce a net to service flow of 2.1×10^5 lbs per day. City water analysis and fuel cell water quality requirements are shown on Table 6.6-2.

Makeup Water Treatment System consists of two (2) Sodium Softeners, (D-602 A&B) a regeneration system, water quality analyzer and a control panel. The system is designed for A or B vessel to run for 12 hours and produce 1.5×10^5 lbs of softened water total. The idle vessel will operate when the operating train is regenerated. The system is designed for automatic operation and to permit the use of either or both vessels simultaneously. The design of this regeneration system includes waste neutralization prior to discharge.

The Condensate Reclaim System shown in Figure 6.6-2 filters collects and tests condensate for quality prior to transfer to the inlet of the vacuum degasifier. It is anticipated that the condensate return from the gasifier process will be suitable for reuse in Fuel Cell thermal management cycle. However, to prevent the introduction of excessive dissolved or suspended contaminants the condensate will be filtered through a 10 micron cartridge filter (G 602 A&B) and collected in

Condensate Prover Tank, D-602, where it will be analyzed and transferred to the inlet of the vacuum degasifier if it is of acceptable quality. Off standard quality condensate will be sent to the waste treatment system.


G - 602 A, B
P - 606 A. B
S - 602
TO FLARE
P - 611
CITY WATER
D- 602 A. B
T -
P - 6
DILUTION WATER
P - 609



DOA / GEORGETOWN UNIVERSITY

COAL GAS/FUEL CELL/COGENERATION

FORT GREELY, ALASKA SITE

FUEL CELL

WATER TREATMENT SYSTEM

FIGURE 6.6-2

EBASCO SERVICES INCORPORATED

TABLE 6.6-1

COOLING WATER SYSTEM LOADS

Equipment	Designation	(10^6 Btu/hr)
Coal Gasification		
Coal Gasifiers	R-101	2.87
Gas Cooling Cleaning and Compression		
Primary Cooler Heat Exchanger	E-201	16.15
Gas Compressor 1st Stage Intercooler	E-202	3.10
Gas Compressor 2nd Stage Intercooler	E-203	4.10
Gas Compressor 3rd Stage Intercooler	E-204	3.85
Ammonia Scrubber Cooler	E-205	.18
CO Shift		
Trim Cooler	E-307	.40
Thermal Management		
Air Compressor Intercooler	E-602	3.20
Steam Turbine Condenser	E-603	23.00
SJAE Condenser	E-604	.19
Miscellaneous Coolers		1.14

6.6.4 Plant Safety

The design of this facility incorporates features required to assure safety of personnel and equipment in the event of an unlikely major leakage of coal gas which is piped at pressures up to 152 psig. The constituents of this coal gas which would be of concern are the hydrogen and the carbon monoxide. The concentration of these components varies through the process from 17 to 32% for hydrogen and from 1 to 24% for carbon monoxide.

The process is located within an insulated metal siding enclosure.

The facility satisfies the criteria of the following governing codes and regulations.

Some of the criteria include:

- OSHA - Requirements for Safe Work places
- NFPA 101 - Life Safety Code
- NFPA 50A - Gaseous Hydrogen Systems
- NFPA 54 - National Fuel Gas Code (Reference)
- NFPA 496 - Purged and Pressurized Enclosures for Electrical Equipment in Hazardous Locations
- NFPA 70 - National Electrical Code
- NFPA - Standards pertaining to detection, suppression and alarm systems

Protection Systems

- Automatic water deluge systems for suppression of ordinary and flammable liquid fires and for reduction of heat, protection of personnel and minimization of facility fire damage.

- Automatic hydrogen and carbon monoxide detection systems and alarms.

- Explosion vents in roof and wall areas of enclosures for gas bearing portions of the process.

- Automatic smoke and/or flame sensing detection and alarm systems.

- All protection systems, including safety related ventilation equipment, are status alarmed in the Control Room. Internal communications - both wireless and hardwired - are provided for roving plant personnel.

6.6.5 Nitrogen Gas Supply

Nitrogen gas is used to pressurize the fuel cell stacks during startup, to purge portions of the system during shutdown and to maintain a nitrogen blanket in certain gas processing equipment and the fuel cell stacks during layup. Shutdown of the fuel cell will cause an automatic nitrogen purge.

The system consists of an insulated liquid nitrogen storage tank with approximate dimensions of 7' diameter by 15' high with a capacity of 4000 gallons. The tank is of a standard cryogenic design equipped for truck refill by a commercial supplier. The liquid nitrogen is vaporized by an air heat exchanger for gas delivery to the system. Gas delivery at 375 psig is initiated by a remote manual signal from the control room, and automatically controlled by pressure and flow control valves.

6.6.6 Hydrogen Gas Supply

Hydrogen is needed by the fuel cell during startup and for passivation of the fuel cells during shutdown. On shutdown the fuel cell stacks are automatically passivated with pure hydrogen, and then purged with nitrogen. Passivation of the cell stacks corrects any local electrode polarization that has occurred due to gas impurities and prolongs the effective life of the cell stacks.

The system consists of truck delivered gas cylinders, containing a total of 200 pounds of hydrogen with an automatic pressure and flow control manifold.

6.6.7 Station and Instrument Air

Clean, dry pressurized air is provided to the fuel cell cathode for passivation, to the fuel cell/cathode air compressor for startup and to all pneumatic instruments. The system consists of a 200 scfm air compressor, dryer and a 100 ft^3 air receiver. Delivery pressure is 125 psig.

6.6.8 Heating and Ventilation

Enclosures for the GFC are served by heating/ventilating air handling units, unit heaters and exhaust fans.

All air heating coils utilize an ethylene-glycol brine to provide reliable operation without danger of freeze damage.

Glycol solution is heated to 200°F in steam to glycol heat exchangers supplied with 40 psia steam from the Thermal Management System. In the event of GFC plant shutdown, the glycol heat exchanger is served with steam from the existing standby oil fired boilers in Heating Plant 606.

Air handling units include in the direction of flow, outside air louvers, and dampers, return air dampers, air mixing plenum, glycol/air heating coil and fan section with duct work or directional air discharges as required.

An economizer control cycle utilizes outside air for cooling to offset internal equipment heat gain during the warmer months.

The recovery of heat from the cooling system described in paragraph 6.6.2 for use in this GFC plant heating system can be effected by rerouting heated glycol to coils in the air handling units and unit heaters described above.

Upon receipt of a high concentration signal from the gas detection system, fans are automatically energized and dampers positioned to limit gas concentrations to safe levels.

6.7 SYSTEM CONTROL (I&C)

6.7.1 Introduction

The instrumentation and control system is configured with centralized control room and control processors. The input/output hardware is distributed functionally and geographically with the process being controlled, the input/output cards being separated from the controllers/processors so that signal wiring and cable maybe reduced by multiplexing. Each major process has a local subsystem control board located close to the process with sufficient displays and controls to operate the process independently of the Control Room.

This configuration conforms to current state-of-art control and instrumentation practice and results in the reduction in signal wires and cable and related construction costs.

Each sensor, transducer and instrument selected is to be the most reliable for the particular application and from a reputable supplier with an extensive service organization. Although different suppliers may be required to furnish the best instrumentation available, only one supplier furnishes the control hardware. This approach reduces the number of spare parts and maintenance training requirements, simplifies system design and consolidates contractual responsibility.

6.7.2 Control System Configuration

The control system is shown functionally in Figure 6.7-1. This includes a plant system processor and controller for each subsystem process. The plant system processor directs and monitors operation of subsystem controllers, providing the logic and sequencing for startup, operation and shutdown.

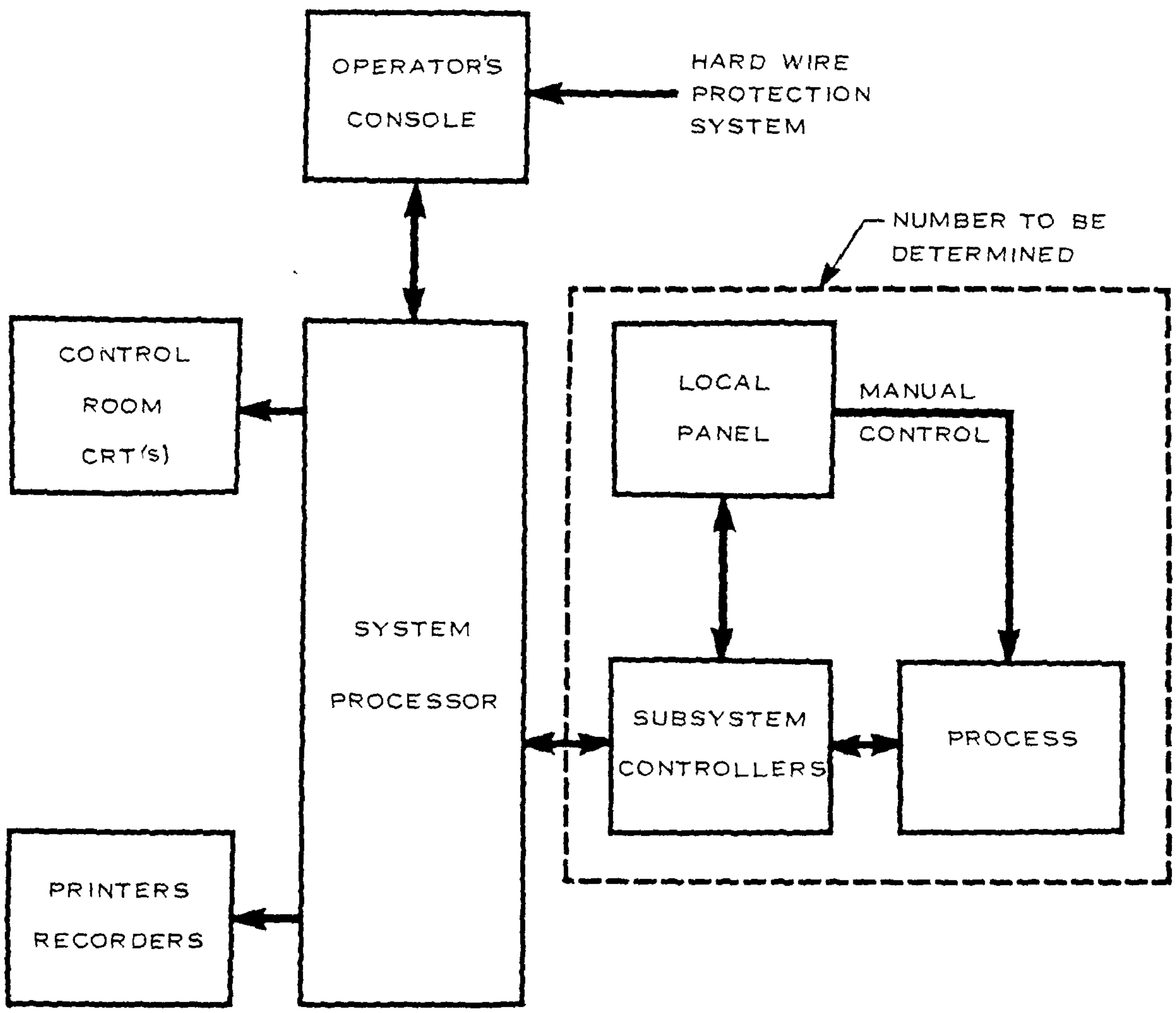


FIGURE 6.7 - 1 CONTROL SYSTEM FUNCTIONAL BLCCK DIAGRAM

The system may be operated from the control room console or from the local subsystem control panels.

The control room contains printers, recorders, CRT's and the operator's control console.

6.7.3 Control Room Layout

The operator interface/peripherals are shown in Figure 6.7-2 and the control room operator's board layout is shown in 6.7-3. The operators console provides for the overall operating mode and power level control in addition to providing dedicated display plant alarms and important process parameters (temperature, pressure, flow, etc).

A separate central analysis console provided for engineering analysis of the process contains a CRT and keyboard to interface with a controller/computer for system analysis. This console is independent of the Control Room operator's console and the local process control boards so that system analysis and performance will not interfere with plant operation.

6.7.4 Control Components and Operation

The system processor (see Figure 6.7-1) is the functional interface with the subsystem controller, furnishing the logic and sequence signals to control the entire plant. Each subsystem, has a controller with local control panel and displays.

There are four color graphic CRT's in the Control Room. One CRT is dedicated to each of the three major processes and the fourth is used for listing alarms and sequence of events during a system malfunction.

One printer is dedicated to preparation of operating and EPA required reports. The second is an alarm logger that tags the alarmed function initially and when it returns to normal.

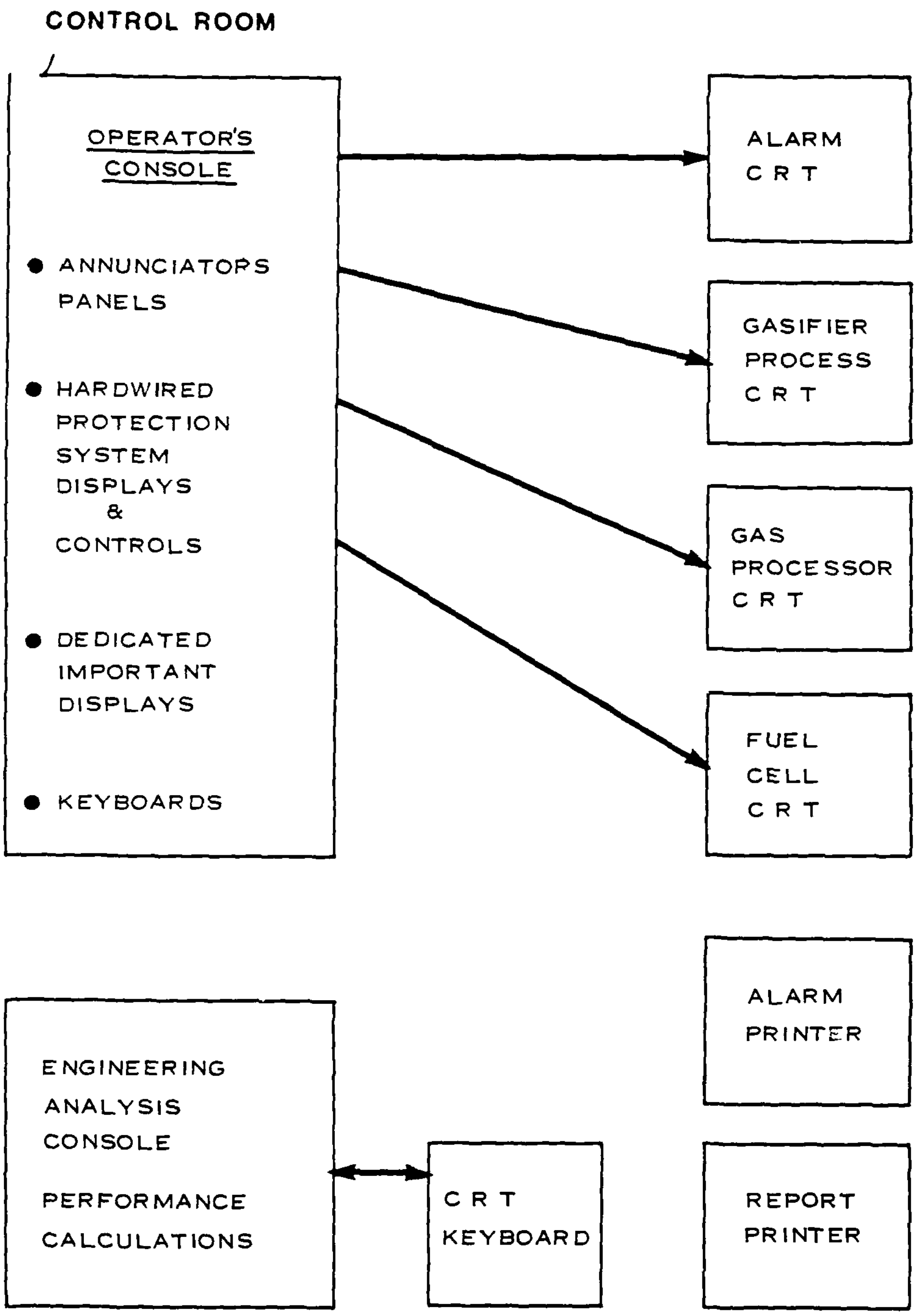


FIGURE 6.7-2 OPERATOR INTERFACE AND PERIPHERALS

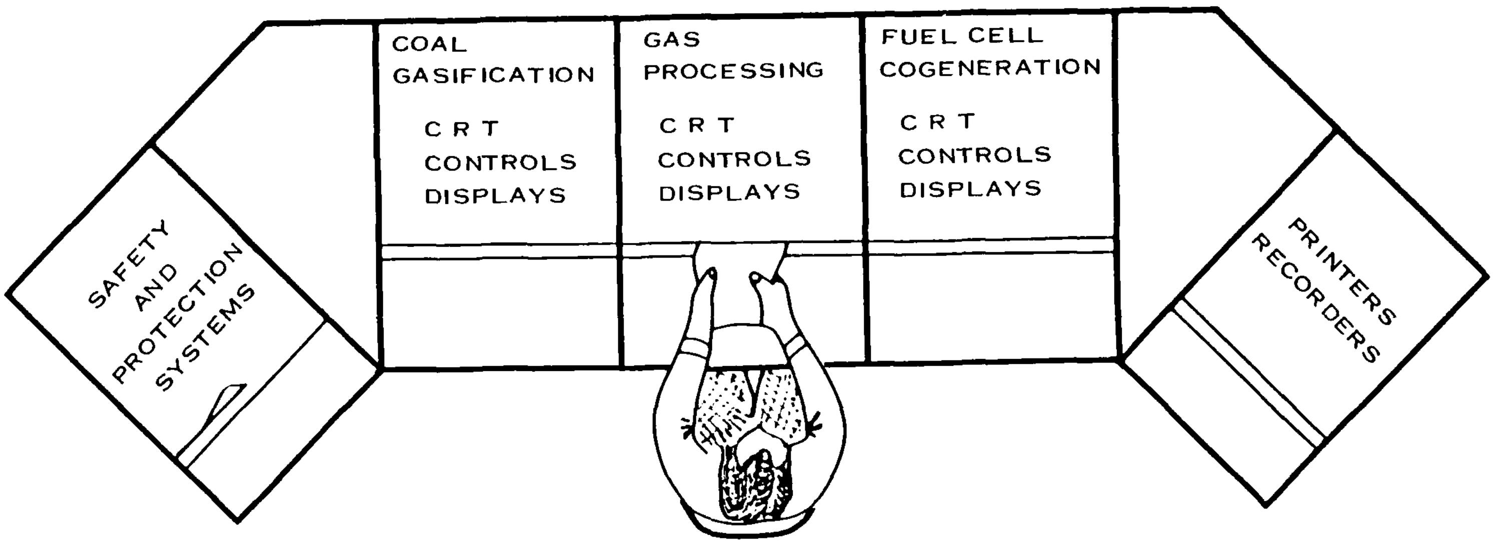


FIGURE 6.7-3 CONTROL ROOM OPERATOR'S BOARD

The process CRT's are color graphic with independent processor, memory and keyboard to format multiple page displays independently of the process controllers. This permits almost instant retrieval of any page without overloading the process controllers, increasing to a point response time.

The control console is in five sections with keyboards, manual controls, dedicated displays, CRT's and annunciator windows. Dedicated displays and manual controls are primarily for the hardwired protection system permitting the operator to override the processors in a major plant upset or component failure. If a failure occurs in the system processor, the plant may continue to operate through local control with subsystem controllers. If a failure occurs in the subsystem controller, there are sufficient manual controls and displays on each local control panel for manual control of the process.

Controls and displays are also included for certain off line ancillaries that are not part of any process subsystem. There is an auxiliary panel in the Control Room for power conditioning and distribution. In addition, there are local auxiliary control panels for material handling (coal and ash), fire protection, and water treatment. A preliminary layout of the control room indicates that approximately 1200 square feet are required for the Control Room and the attached Electronics Room. Supporting facilities, offices, store room, conference room, etc., are not included in this estimate.

6.7.5 Safety

A complete system for monitoring and detection of safety conditions throughout the plant is provided. Conditions including fire, smoke, gas concentration and malfunctions in safety related systems are indicated and annunciated in the Control Room (refer to paragraph 6.6.4). Audio alarms are located as required throughout the plant.

6.7.6 System Control Description

6.7.6.1 Coal Gasification

a. Firebed and Ash Zones

Immediately above the ash bed is the combustion (firebed) zone. In the lower part of the firebed, carbon dioxide is formed from carbon in the fuel and the oxygen in the air/steam blast. Further up, the carbon dioxide combines with carbon and is converted into carbon monoxide. The delivery of the correct quantity of gas with uniform quality is ensured by maintaining these various zones at the proper level and thickness and by a suitable air/steam supply.

The above information on the fire and ash bed is determined by insertion of a steel rod. The dark end of the withdrawn rod indicates the ash depth; the portion of the rod glowing red, indicates the combustion zone; the next darker color indicates the reduction zone. These checks are performed every four to eight hours.

Depth of the fire bed is normally between 4 and 8 inches and of the ash bed, between 12 and 20 inches. If ash bed depth is greater than desired, grate rotation speed is manually increased. Too great a depth of ash can decrease gas production while too shallow a depth reduces grate insulation and protection of the grate from excessive temperatures.

b. Gas Pressure Control

Gas pressure control is the main loop since steam, coal and gasification rates depend on air supply. To prevent air inleakage, the system is maintained under positive pressure. The output of the gasifier is regulated by a recorder controller sensing pressure in the suction line

of the gas compressors. As producer gas fuel cell demand increases and line pressure decreases, the controller modulates the air control valve admitting more air to the grate, increasing the rate of gasification. The air flow is modulated to suit demand. E.g., if gas pressure increases, air flow is reduced to lower the gasification rate.

c. Blast Saturation Temperature

Process water is evaporated into the air supply to control the fire bed temperature at a level where gasifier operation is optimized and the ash is prevented from clinkering. The water vapor content of supply air is controlled through a jacket water temperature controller. By modulating a valve in the jacket water circuit, temperature and therefore evaporation rate is maintained at the setpoint. The setpoint may be manually adjusted to maintain optimum firebed conditions. Steam injection is controlled by air flow to the gasifier.

d. Fuel Feed Level Control

The fuel feed to the gasifier is automatically controlled by a level detector in the upper bin to maintain its setpoint regardless of load change. As fuel is consumed a limit switch actuates the lockhopper valve through a motor operator located under the bin. To fill the lower bin, the bottom valves are closed and the upper valves opened, allowing coal to flow by gravity into the lockhopper. When the lockhopper is filled, usually in a matter of a few minutes, the upper valves close and lower valves open.

e. Grate Rotation

The rotational speed of the gasifier grate is automatically maintained at a point that is manually reset as required to maintain the correct depth of ash, and a safe firebed position.

The grate operates under the control of a timer mechanism consisting of a manually adjustable controller that controls the frequency that oil is admitted to hydraulic through a solenoid valve.

f. Flare Systems

Gasifier output normally matches fuel cell requirements. However, automatic flare systems are provided to burn excess gas which may be produced under off-normal conditions.

These flare systems include a pilot burner with automatic start and shutdown.

The flare is used during startup before the system has been fully purged and pressurized and also while any tests are performed with the gasification system.

Equipment failure is one event which results in excess gas being generated. The gas is flared until the gasifier throughput has been reduced to the appropriate level. In the event of power failure, the gasification system is automatically shutdown as a fail-safe operation with the gas being flared.

The flare is also used to burn any excess fuel gas generated during fuel cell load reduction.

6.7.6.2 Gas Cooling, Cleaning and Compression

a. Anti-Surge Control for Centrifugal Compressors

The differential pressure between the suction and discharge line of the compressor is monitored in conjunction with a discharge line flow controller. The discharge line is defined as downstream of the third stage K.O. drum. A signal generated by differential pressure divided by flow will either open or close a flow control valve to send fuel gas from the discharge line back to the suction line through a bypass line.

b. Ammonium Sulfate Recovery

The ammonium sulfate saturator is controlled by liquid level and temperature. The quantity of sulfuric acid to the tower is controlled by level. Temperature setpoint error in the tower is cascaded to a flow control loop to control flow upstream of the ammonia scrubber exchanger by modulating the valve on the wash liquid line. A manually adjustable controller maintains flow of the ammonium sulfate from the tower at constant rate.

c. CO Shift

The principal control philosophy for the CO shift section is based on maintaining the required temperature and steam to gas ratio inlet to the CO shift reactors. This is accomplished by temperature measurement in the top section of both reactors transmitting signals to the control system to position the valves on the bypass lines around the feed/effluent heat exchanger II and CO shift steam generator. The proper steam to gas ratio to the first CO shift reactor is maintained by flow control of the combined steam line from the CO shift steam generator and import steam line, by modulating the flow control valve on the steam import line. Both reactors will have temperature alarms in the top section of the catalyst bed and analyzer recorder alarms in the exit lines of the reactors to monitor CO concentration and steam to gas ratios.

Both the K.O. drum and trim cooler K.O. drum, are level controlled.

The fuel cell feed heater has a bypass line on temperature control for the fuel gas stream based on the temperature of the ZnO beds.

d. Sulfur Removal and Recovery

The principal control loops and instrumentation for the Sulfur Removal and Recovery section are:

- The proper liquid to gas ratio is maintained in the venturi contactor by control of liquid level at the bottom of the vessel in conjunction with a level control valve on the line from the solution heater to the top of the reactor and a flow controller on the line to the venturi scrubber.

- The slurry decanter is level controlled and temperature control is maintained on the steam condensate line to ensure the flow of molten sulfur.

- The zinc oxide beds are flow controlled such that before hydrogen sulfide breakthrough occurs in the first drum there is interchange of flow between the first and second vessel. Both reactors have analyzer recorder alarms for monitoring hydrogen sulfide concentration levels.

- Exiting the zinc oxide vessels, the fuel gas flow to the fuel cells is pressure controlled. In the event there is an increase in line pressure, the control system will send a split signal to: (1) a control valve to open, thereby releasing the fuel gas to a common flare connected with the gasifier and (2) the suction line of the gas compressors pressure control system which in turn sends a signal to the air blower to maintain the required air flow to the gasifier thereby decreasing the gasification rate.

  In the event line pressure decreases the PRC performs the function of increasing the air flow rate thereby increasing fuel gas production.

6.7.6.3 Fuel Cell

The fuel cell system is designed for semi-automatic operation, requiring no operators in addition to those assigned to the Gas Processing Section. The fuel cell system is controlled by micro-processor based controllers that allow the operator to select the operating mode of the plant and the power level. The control system also automatically shuts the plant down during certain upset conditions.

During operation the power conditioner control automatically maintains the desired AC power level. The fuel cell controllers respond to the power demand of the power conditioning system by maintaining the appropriate DC current output. DC current is the prime parameter which controls the setpoints for the remainder of the system. The fuel cell controllers also monitor and control certain portions of the other systems to insure proper operation of the fuel cell.

In addition to manually selecting the AC power output, the operator can select any of the following operating modes:

- cold stop
- standby
- power

Transition between operating modes can be automatic or manual. Cold start-up or shutdown requires manual action, while all other operation is automatic with manual override. Emergency shutdown due to upset conditions is automatic.

In the off state, the fuel cells are maintained under a nitrogen blanket and heated to a temperature of 100°F by electric heaters. In the standby mode, the cell are heated above 250°F by the circulating air. The air circulator rotates at low speed with the circulating air heated by an electric heater associated with the heat recovery steam boiler.

On proceeding to the power mode, hydrogen rich anode flow is initiated and air flow to the cathode is adjusted for 50% stoichiometry. When a minimum voltage is reached the power conditioner is connected to the cell stacks, and the electrochemical reaction raises the cell temperature further. Anode pressure is raised in steps following DC current, air stoicometry and temperature limitations until 35% power is reached. At this point, a smooth transition can be made to any power level and power can be sent to the utility grid. The automatic controllers will maintain operating conditions with the allowable pressure/temperature region shown in Figure 6.4-2. Cathode air is aloways controlled to maintain a 50% utilization.

The power conditioner individually controls the current from each fuel cell module so that a uniform temperature is maintained without having to make minor adjustments in air, fuel or cooling flow. The mean temperature is determined by the gross DC current and controlled by varying the vanes on the air circulator. Anode flow is controlled by a flow control valves and the mass flow of the air compressor is controlled by adjusting the bypass flow.

On entering standby or cold stop, the cell stacks are passivated with pure hydrogen from the hydrogen supply system, and the system is purged with nitrogen.

Certain off-standard conditions in the fuel cell are alarmed and cause automatic shutdown to either standby or cold stop depending on the condition. The status of other systems is also monitored and the fuel cell may be shut down if the systems are not within their operating range.

6.7.6.4 Thermal Management System

TMS equipment operates automatically, maintaining constant boiler steam conditions regardless of fuel cell load.

Pressure control valves on steam lines maintain boiler drum and steam user pressures at the required set points.

Makeup water flows to and HRSG steam drums (B-602,-601) are regulated by makeup water control valves based on drum water level. Likewise, deaerator (D-601) and condensate tank (S-601) water levels are maintained by makeup water control valves, and condenser (E-603) hotwell level is controlled by the discharge valve at the outlet of the condensate pumps (P-602A,B).

For gas side transients such as generator G-601 trip, gas expander bypass control valves open to prevent expander overspeed. Additional valves to the HRSG inlet and HRSG auxiliary burner controls modulate as required to maintain HRSG steam pressure.

To compensate for variations in process and export steam demand which may result in varying fuel cell cooling air temperature exiting HRSG B-602, the water supply to the economizer section is modulated to maintain the leaving air temperature. Water supply exceeding TMS makeup water requirements is bypassed to the condensate storage tank. (A water to water heat exchanger may be required to prevent the build-up of tank heat). If the required HRSG economizer water supply flow is below TMS makeup requirements then the additional makeup water flow is bypassed around the HRSG.

7.0 ENVIRONMENTAL

This section reviews the emissions which will be generated by the Gasification/Fuel Cell/Cogeneration (GFC) system serving the Fort Greely site, and briefly discusses the major federal and Alaska regulatory requirements expected to affect construction and operation of the GFC. For this study is is assumed that all process wastewater will be discharged into the existing Fort Greely main post sewage treatment plant.

Therefore for this study it appears, based upon the facts, assumptions, laws and regulations discussed in this section that: 1) the GFC system as presently conceived requires little or no further emission control measures; 2) the major permits/licenses/approvals necessary for construction and operation of the GFC can be obtained without undue difficulty or delay.

7.1 Summary of Emissions and Regulatory Limitations

Estimates of the air, water, and solid/hazardous waste streams expected to be produced by the GFC are listed in Tables 7-2 through 7-5. For a comparison of GFC system emissions and discharges with regulatory limits, refer to Table 7-1. This table indicates that this project appears to be environmentally acceptable. Each category of emissions and the major regulatory limits expected to apply are summarized in Table 7-6 and briefly noted as follows:

The GFC emissions (Table 7-2) of so-called criteria pollutants (NO_x, SO_2, CO, particulates, H_2S) are below the limits which trigger the federal Clean Air Act (CAA) Prevention of Significant Deterioration (PSD) permit process administered by the State of Alaska[1]. Briefly stated, a major source is defined as: 1) specified kinds of sources that emit 100 tons/year or more of any CAA- regulated pollutants and 2) any source which emits 250 tons/year or more of any CAA-regulated pollutant. Major modifications are those which increase emission rates of an existing major

source above the threshold values listed in Table 7-7. Because the other power generating and heating facilities do not operate simultaneously with the GFC, the GFC is neither itself a "major" source, nor can it be a "major modification" of any existing major source. This is also true if a UTC cell is used in lieu of a Westinghouse cell.

A permit to operate will be required from the Alaska Department of Environmental Conservation (DEC). The GFC estimated air emissions are below the levels for "major sources" under Alaska Air Quality Control Regulations. The following are specific emission limitations expected to apply to the GFC.

$\underline{SO_2}$ - Alaska emission limitations require that SO_2 emissions not exceed 500 ppm by volume averaged over a 3 hour period.

Particulates - Alaska emission limitations require that GFC particulate emissions not exceed 0.05 grains/standard cubic foot of exhaust gas volume.

Opacity - Alaska emission limitations require that visible emissions (opacity) not exceed 20% averaged over a 3 minute period.

$\underline{H_2S}$ - Alaska does not have H_2S emission limitations for a facility of this size.

7.1.1 Water

For this study it is assumed that the process wastewater streams expected to be produced by the GFC (Table 7-3) will be discharged to the existing Fort Greely treatment system. Note that the volume of the wastes expected (approximately 27,500 gpd) is about 12% of the maximum recorded wastewater volume currently discharged to the main plant treatment system (about 223,000 gpd). Since the additional volume of wastes represents a small fraction of the current Fort Greely discharge, for this study it is assumed that any necessary permit modification approvals can be obtained without undue delay or difficulty.

With regard to additional stormwater runoff from the GFC, it is assumed that this waste stream will be added to the existing Fort Greely drainage system. This is expected to require a modification to the existing NPDES permit for the stormwater discharge to Jarvis Creek. Note that since Alaska has not been delegated NPDES permitting power, a dual permit is issued by both the Alaska DEC and EPA Region X.

7.1.2 Solid/Hazardous Wastes

The solid/hazardous waste streams expected to be produced by the GFC are summarized in Table 7-4 and 7-5. It will be necessary to determine which in fact might be considered hazardous wastes under EPA's Resource Conservation and Recovery Act (RCRA) hazardous waste regulations since Alaska does not have hazardous waste review authority. At the present time, the burning of hazardous wastes for legitimate energy recovery purposes is exempt from RCRA regulation, but this may change in the future(3).

Fort Greely presently has systems in place for collection, holding, and removal of solid and hazardous wastes streams now being generated. For this study is assumed that the additional GFC waste streams can be easily integrated into these existing procedures.

7.2 Applicable Laws and Regulations

The major federal and Alaska laws and regulations expected to affect construction and operation of the GFC will be briefly noted. This discussion is premised upon the assumptions and estimated emissions already discussed.

7.2.1 Air

7.2.1.1 Federal

A federal Clean Air Act PSD permit is not required for the GFC, because the quantity of regulated pollutants is insufficient to activate PSD the permit process. However, it appears that the GFC must comply with the

New Source Performance Standard (NSPS) for "coal preparation plants", which would limit opacity from the coal handling section of the GFC to below 20%.

7.2.1.2 Alaska

As discussed above, the Alaska Air Quality Control Regulations require a permit to operate the GFC, based in part upon a showing that a new source such as the GFC meets "Best Available Technology". "Best Available Technology" is defined as that available technology which will prevent, reduce, or control air emissions to the "maximum degree possible." Since the GFC is not considered a "major source" under Alaska standards, for this study it appears that the necessary approvals likely can be obtained upon a showing that the emission limitations discussed above and set forth in Table 7-8 (SO_2, particulates, opacity) will be met by the GFC.

7.2.2 Water

7.2.2.1 Federal

The federal Clean Water Act National Pollutant Discharge Elimination System (NPDES) permit program in Alaska is administered by EPA Region X. Therefore, a modification to a Federal NPDES permit may be required if the GFC waste streams will change either the volume of effluent or quantity of pollutants discharged from the wastewater treatment plant accepting the GFC waste streams.

The EPA has established New Source Performance Standards (NSPS) for runoff from coal piles at steam electric plants which might be applied to the GFC's coal piles. The NSPS for coal pile runoff require a pH within the range of 6.0 to 9.0 and contain a maximum concentration limitation of 50 mg/l for total suspended solid (TSS). This maximum concentration for TSS does not apply to untreated overflow from a facility designed for a 10-year, 24-hour rainfall event.

TABLE 7-1

GFC EMISSIONS VERSUS REGULATORY LIMITS

Air	GFC Emission, (tons/year)	Regulatory Limit, (tons/year) EPA(1)	AL
NO_x	71.4	250	
SO_2	71.0 (of SO_x)	250	(2)
CO	18.1	250	
Particulates	1.6	250	(3)
H_2S	0.03	250	

Water	GFC Emissions(4) (mg/l)	Regulatory Limit(6) (mg/l)
COD	150	
Phenol	0.3	
Sulfur	Not Available	
pH	(6-8.5)(5) pH units	
Chlorine	less than 0.1	
Metals	Not Available	
Suspended Solids	20	

Solid Waste

Solid wastes determined to be hazardous will be managed according to requirements of the Resource Conservation and Recovery Act, as administered by the EPA Region X.

Noise

GFC Emission	AL. Limit
55 dB at 100 feet	None

TABLE 7-1 (Cont'd)

Notes:

1. Clean Air Act PSD no "major source" limits. If these limits are exceeded a federal PSD air permit would have to be obtained for the project.

2. Alaska limits SO_2 in the stack to 500 ppm by volume averaged over a 3-hour period.

3. Alaska limits particulate emissions to 0.05 grains/standard cubic foot of exhaust gas volume.

4. The concentrations listed are for the relevant waste stream. The concentrations at the GFC discharge point will be lower than those listed due to dilution from the mixing of different waste streams. One possible exception to this is the waste stream containing chlorine which may have to be discharged separately and undiluted into the sewer system to prevent it from combining with phenol.

5. The pH of project effluent at the point of discharge.

6. Regulatory requirements to be determined after assessment of treatability of GFC emissions in existing pretreatment facilities.

TABLE 7-2

ESTIMATED AIR EMISSIONS

	Emission	Quantity (lb/day)	Source
Coal Handling	Dust	Negligible	
Gasification(1)			Gasifier lock-hopper
	H_2	2.0	
	CO_2	4.04	
	C_3H_4	0.22	
	C_2H_6	0.20	
	N_2	66.81	
	CH_4	1.38	
	CO	38.48	
	H_2S	0.09	
	COS	0.02	
	NH_3	0.06	
	HCN	0.01	
	H_2O	28.43	
Gas Processing	NO_x	22.8	Ammonia Flare
	H_2S	0.15	Stretford Oxidizer
Fuel Cell	NO_x	92.3	Catalytic Combustor
	SO_x	2.1	
	TSP (Particulates)	2.9	
	Smoke	Negligible	
Thermal Management System (2)	NO_x	367.6	
	SO_x	478.4	
	TSP	11.0	
	CO	83.8	

Notes:

1. Maximum possible emissions per day which could occur during the opening of the lockhopper valves during coal feeding.
2. Includes site specific increment.

TABLE 7-3

ESTIMATED WATER EMISSIONS

	Flow (GPD)	Emission	Concentration (mg/l)	Disposal
Coal Processing	300	Not Available	Not Available	Existing Collection System
Gasification				
Treated Waste Water	39,580			
		COD	150	To site Treament
		Phenol	0.3	
		NH_3	1	
		Suspended Solids	20	
Sulfur Wash Water	6,540	Sulfur	Not Available	
Ash Sluice Water	300	Not Available		
Fuel Cell	None			
TMS				Existing Collection System
Regen Wastes	10,000	Turbidity	20 NTU (6-8.5) pH units	
Boiler blowdown	4,180	Suspended Solids	20 (6-8.5) pH units	
Cooling Tower Blowdown	11,000	Chlorine	0.1 (6-8.5) pH units	

TABLE 7-4

ESTIMATED SOLID WASTES

	Solid Waste Quantity	Pollutant	Pollutant Quantity	Disposal
Coal Handling	N/A(1)	Dust/Fines	NA	NA
Gasifier				
Ash	22.0 TPD	Trace elements including Be, B, CO, Cr, Cu, Ge, Mn, Ni, U and V.	NA	Carted away to landfill waste disposal
Cyclone Dust	2.6 TPD	Same trace elements as in ash	NA	Carted away to landfill or hazardous waste disposal
Spent Catalysts			NA	Carted away to landfill
CO shift	67 CF/Yr	Sulfur Compounds	NA	
COS Hydrolysis	2 CF/Yr	Sulfur Compounds	NA	
Purged Stretford solution	9 GPD	(2)	(2)	Carted away to hazardous waste disposal
ZnO From Gas Polishing	9 CF/Yr	ZnS	NA	Carted away to landfill
Wastewater Treatment Slurry	480 GPD	Heavy Metals	NA	Carted away to landfill or hazardous waste disposal
Fuel Cell	320 CF/Yr	Heavy Metals in spent catalyst and in replaced cell stacks	NA	Returned to manufacturer for recovery
TMS	None			

Notes:

1. NA - Not available
2. See Table 7-5.

TABLE 7-5

COMPOSITION OF BLOWDOWN FROM STRETFORD PROCESS[1]

Constituent	Concentration (mg/l)
$NaHCO_3$	25,000
Na_2CO_3	5,200
$NaVO_3$	6,600
Anthraquinone Disulfonic Acid	10,000
Iron	50
EDTA	2,700
$Na_2S_2O_3$	120,000
NaCNS	90,000

Note:

1. Based on the complete conversion of HCN in gas feed to NaCNS; 2% conversion of H_2S to $Na_2S_2O_3$; and salt concentration of 25%.

TABLE 7-6

SUMMARY OF ENVIRONMENTAL REQUIREMENTS

Federal

National Environmental Policy Act processing Revision to EPA Form 1 on storm water discharges.

Clean Air Act New Source Performance Standard for coal preparation plants.

Compliance with RCRA solid waste management guidelines.

Modification (potential) to NPDES permit for wastewater treatment discharge.

Alaska

Alaska air permit.
Compliance with Alaska solid waste management controls.
Compliance with Erosion and Sedimentation Control Plan requirements.

TABLE 7-7

THRESHOLD EMISSION LEVELS FOR MAJOR MODIFICATIONS UNDER THE CLEAN AIR ACT PSD PERMIT PROGRAM

Pollutant	Emission Rate, tons/yr
CO	100
NO_x	40
SO_2	40
Particulates	25
Ozone	40 of VOC's
Lead	0.6
Asbestos	0.007
Beryllium	0.0004
Mercury	0.1
Vinyl Chloride	1
Fluorides	3
Sulfuric Acid Mist	7
H_2S	10
Total Reduced Sulfur (including H_2S)	10
Reduced Sulfur Compounds (including H_2S)	10

TABLE 7-8

APPLICABLE REQUIREMENTS OF THE ALASKA AIR QUALITY CONTROL REGULATIONS

SO_2	Emissions cannot exceed 500 ppm by volume averaged over a 3-hour period
Particulates	Cannot exceed 0.05 grains/standard cubic foot of exhaust gas.
Visible Emissions	Opacity cannot exceed 20% averaged over a 3 minute period.

7.2.2.2 Alaska

As discussed above, all process wastewater from Fort Greely is now discharged into the Main Post treatment system, and all stormwater runoff is discharged into Jarvis Creek. Both discharges are regulated by a discharge permit jointly issued by the Alaska DEC and EPA Region X. If any additional volume of discharge or quantity of pollutants results from the addition of the GFC waste streams, a modification may be required to the Alaskan/EPA ultimate discharge permit.

7.2.3 Solid/Hazardous Waste

7.2.3.1 Federal

The Resource Conservation and Recovery Act (RCRA) regulates the management of hazardous wastes and, to some extent, the management of non-hazardous solid wastes. The RCRA Hazardous waste management program in Alaska is administered by EPA Region X (see 7.1.2). Note that the GFC, if operated as a federal facility, would be subject to the RCRA solid waste management guidelines. For this study it is assumed that these have already been implemented at Fort Greely.

7.2.3.2 Alaska

Alaska has not been delegated authority to implement the EPA RCRA program.

7.2.4 Other State and Local Environmental and Land Use Requirements

The GFC project will need to comply with several other laws and regulations, and obtain several other permits, licenses, and approvals. These include the normal zoning and building regulations associated with new facility construction.

7.2.5 National Environmental Policy Act

NEPA requires federal agencies to consider the effects of their actions upon the human envirofnment. The Department of the Army (DOA) is required to undertake a NEPA review of the GFC project because of the use of federal funds and the construction of a new energy facility for an Army installation[4].

Note that the level of NEPA compliance varies with the expected impact of the proposed action. For this study it is assumed that a full Environmental Impact Statement (EIS) will not be required. It is anticipated that DOA would prepare an Environmental Assessment, a relatively brief document, and issue a Finding of No Significant Impact (FONSI) after review and public comment on the EA.

7.3 References

7-1 Code of Federal Regulations, Title 40, Part 52.21.

7-2 Alaska Air Quality Control Regulations, 18 AAC 50.

7-3 Federal Register Vol. 50 p 630 (January 4, 1985)
Federal Register Vol. 50 p 17824 (April 29, 1985)

7-4 Code of Federal Regulations, Title 32, Part 651.

8.0 APPENDICES

A. Equipment List

B. Alternate UTC Fuel Cell System

C. Mass Balance Bases

APPENDIX A

EQUIPMENT LIST

COAL HANDLING AND STORAGE SECTION

Item No	Quantity	Description
H-001	1	24" Variable speed Belt Feeder, 150 TPH Estimated HP=15
H-002	1	24" Belt Conveyor 350; lg x 100' lift, 150 TPH coal, 400 FPM, HP=25
H-012	1	24" Belt Weighfeeder w/variable speed drive, rate indicator, totalizer, flow gate, and dust hopper w/scavenger screw. 0-20 TPH Estimated HP=5
H-009	1	24" Belt Conveyor 230' ft. lg x 70' lift, 15 TPH coal, 100 FPM, 75 HP
H-011	1	24" Tripper Conveyor w/self propelled tripper. Length 160 ft., Lift=50 ft., 15 TPH coal, 100 FPM. Conveyor=7.5 HP, Tripper=2 HP
H-013	1	Vibrating Screen 15 TPH, 1/4" opening, Estimated HP=5
P-001,A,B	2	Sump Pump 50 GPM; Estimated HP=2HP Each
P-002A,B	2	Sump Pump 15 GPM; Estimated HP=2HP Each
S-001	1	Grizzly covered, steel receiving hopper 14'x14' square top x 15' deep w/water spray nozzle dust control system below truck unloading station.
S-002	1	20' Dia. 60' high silo, 200 T capacity coal, 45 lb/ft^3 w/10 ft. clearance under discharge cone.
S-003	1	Fines silo, 15' Dia. x 27' high w/manual discharge gate w/16' clearance under discharge gate
T-001	1	Truck scale w/automatic ticket printer
T-002	1	Magnetic separator, Estimated HP=2
G-001 A, B, C	3	Bag type dust collector w/2 100% capacity blowers at 30 HP

EQUIPMENT LIST

Item No	Quantity	Description
COAL GASIFICATION SECTION		
R-101, A & B	2	Coal Gasification system including airblown, atmospheric pressure, single stage, 10' ID fixed-bed coal gasifier and cyclone dust collector (H-102 A & B)

EQUIPMENT LIST

Item No	Quantity	Description
GAS COOLING CLEANING AND COMPRESSION SECTION		
C-201	1	Gas compressor - centrifugal, stainless steel, three stage w/inter cooling between stages, with a capacity of 8,646 SCFM and designed for 121 psia at 150°F, driven by 2193 hp electric motor. Including oil system, seal system and instrumentation.
D-201	1	Gas compressor 1st stage K.O. drum, - stainless steel, with mist eliminator designed for 45 psig at 150°F, 4'-6" diameter x 9'-0" high
D-202	1	Gas compressor 2nd stage K.O. drum, - stainless steel, with mist eliminator designed for 75 psig at 150°F, 3'-9" diameter x 7'-6" high
D-203	1	Gas compressor 3rd stage K.O. drum, - stainless steel, with mist eliminator designed for 135 psig at 150°F, 3'-0" diameter x 6'-6" high
D-204	1	Tar separator - coalescer plates installed in fabricated steel tank, 8'x2'-9'x2'-9" high with a capacity of 55 gpm
E-201	1	Liquor cooler - designed for 15.20 x 10^6 Btu/hr duty, with 2100 ft^2 effective area, in carbon steel
E-202	1	Gas Compressor 1st stage intercooler, with stainless steel tubes and carbon steel shell, designed for a duty of 1.68 x 10^6 Btu/Hr duty, with 374 ft^2 effective area. Furnished with C-201
E-203	1	Gas Compressor 2nd stage intercooler, with stainless steel tubes and carbon steel shell, designed for 1.01 x 10^6 Btu/Hr duty, with 225 ft^2 effective area. Furnished with C-201

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EQUIPMENT LIST (Cont'd)

GAS COOLING CLEANING AND COMPRESSION SECTION (Cont'd)

Item No	Quantity	Description
E-204	1	Gas Compressor 3rd stage cooler, with stainless steel tubes and carbon steel shell, designed for 727,000 Btu/hr duty, with 162 ft^2 effective area. Furnished with C-201
E-205	1	Ammonia scrubber cooler, with stainless steel tubes and carbon steel shell, designed for 37,000 Btu/Hr duty, with 26 ft^2 effective area
P-201 A,B	2 (1 Spare)	Saturator pump, - carbon steel centrifugal horizontal, rated for 120 gpm at 80 ft, driven by 5 hp electric motor
P-202 A,B	2 (1 Spare)	Tar pump-carbon steel gear type, rated for 25 gpm and driven 1/2 hp electric motor
P-203 A,B	2 (1 Spare)	Liquor pump-carbon steel centrifugal horizontal rated for 40 gpm at 40 ft, driven by 1.5 hp electric motor
P-204 A, B	2 (1 Spare)	Primary cooler pump, stainless steel centrifugal horizontal rated for 3057 gpm at 120 ft, driven by 125 hp electric motor
P-205 A, B	2 (1 Spare)	Acid circulation pump, - stainless steel centrifugal horizontal, rated for 29 gpm at 50 ft, driven by 1.5 hp electric motor
S-201	1	Tar collection tank - 6 ton capacity vertical carbon steel tank designed for 30 psig at 190°F. 5' diameter x 12' high
S-202	1	Liquor collection tank - 3 ton capacity vertical carbon steel tank designed for 30 psig at 150°F. 3'-6" diameter x 10'-0 high
T-201	1	Saturator - direct contact spray tower, designed for 30 psig at 530°F, in carbon steel. 4'-10" diameter x 80'-0" high

EQUIPMENT LIST (Cont'd)

GAS COOLING CLEANING AND COMPRESSION SECTION (Cont'd)

Item No	Quantity	Description
T-202	1	Primary cooler - venturi type scrubber, designed for 30 psig at 200°F, in carbon steel with stainless steel internals. 7'-2" diameter x 13'-0" high
T-203	1	Ammonium sulfate saturator - stainless steel tower, designed for 135 psig at 150°F. 2'-6' diameter x 14'-0" high
J-201	1	Dispersed phase precipitator - wet electrostatic precipitator, designed for 15540 ACFM, with 99% efficiency, 14.3 kW, 20 KVA, carbon steel.

CO SHIFT SECTION

Item No	Quantity	Description
D-302	1	Trim Cooler K.O. Drum - stainless steel vessel designed for 92 psig at 150°F, with wire mesh separator. 3'-2" diameter x 6'-0" high
E-301	1	Feed/Effluent Heat Exchanger II- designed for 3.04 x 10^6 Btu/Hr duty with 205 ft^2 effective area. 1-1/4 Cr-1/2 MO tubes, stainless steel shell.
E-302	1	Feed/Effluent Heat Exchanger I - designed for 1.5 x 10^6 Btu/Hr duty with 103 ft^2 effective area. 1-1/4 Cr - 1/2 MO tubes, stainless steel shell
E-303	1	CO Shift Steam Generator - Kettle type heat exchanger designed for 1.8 x 10^6 Btu/Hr duty with 265 ft^2 effective area. 1-1/4 Cr - 1/2 MO tubes, stainless steel shell
E-304	1	Fuel Cell Feed Preheater - stainless steel heat exchanger designed for 2.9 x 10^6 Btu/Hr duty with 392 ft^2 effective area

EQUIPMENT LIST (Cont'd)

CO SHIFT SECTION (Cont'd)

Item No	Quantity	Description
E-305	1	Feed Gas Preheater - stainless steel heat exchanger designed for 2.4 x 10^6 Btu/Hr duty with 1202 ft^2 effective area
E-306	1	Air Cooler - stainless steel, designed for 10.0 x 10^6 Btu/Hr duty with 2564 ft^2 effective area and 45 hp fan
E-307	1	Trim Cooler - designed for 0.5 x 10^6 Btu/Hr duty with 227 ft^2 effective area. Stainless steel tubes and carbon steel shell
F-301	1	Start-up Heater - fired heater, designed for 15 x 10^6 Btu/hr duty and used for start-up only
R-301	1	1st CO Shift Reactor - 1-1/4 Cr-1/2 MO converter, designed for 170 psig at 930°F. 4'-0' diameter x 12' - 5" high packed with 105 ft^3 sulfided shift catalyst
R-302	1	2nd CO Shift Reactor - 1-1/4 Cr-1/2 MO converter, designed for 170 psig at 610°F. 4'-0' diameter x 11'- 8" high, packed with 96 ft^3 sulfided shift catalyst

SULFUR REMOVAL AND RECOVERY SECTION

Item No	Quantity	Description
D-402 A, B	2	ZnO Drum - carbon steel vessel designed for 75 psig at 400°F 7'-0" diameter x 12'-2" high, packed with 313 ft^3 ZnO absorbent
R-401	1	Hydrolysis Reactor - carbon steel vessel designed for 75 psig at 400°F, 6'-0" diameter x 12'-8" high, packed with 245 FT^3 COS hydrolysis catalyst

EQUIPMENT LIST (Cont'd)

SULFUR REMOVAL AND RECOVERY SECTION (Cont'd)

Item No	Quantity	Description
X-401	1	Stretford Sulfur Removal and Recovery Package, including: C-401 Air blower D-401 Slurry decanter E-401 Solution heater H-401 Solid separation, wash and reslurry S-401 Oxidizer tank S-402 Balance tank S-403 Slurry tank T-401 Venturi contactor Nominal sulfur capacity 0.3 STPD

PROCESS CONDENSATE TREATMENT SECTION

Item No	Quantity	Description
G-501 A, B	2 (1 Spare)	Carbon Filter - carbon steel plate and frame filter press designed for 4400 gpd flow with 4.5% solids dewatered to 35% solids
E-501	1	Sour Water Heater - stainless steel heat exchanger, designed for 957,000 Btu/Hr duty with 95 ft^2 effective area
P-501 A, B	2 (1 spare)	Sour Water Pump - stainless steel centrifugal horizontal rated for 25 gpm at 120 ft and driven by 2 hp electric motor
P-502 A, B	2 (1 spare)	Waste Water Pump - stainless steel centrifugal horizontal, rated for 25 gpm at 40 ft and driven by 1 hp electric motor
P-506 A, B	2 (1 spare)	Recycle Water Pump - carbon steel centrifugal horizontal, rated for 55 gpm at 40 ft and driven by 1.5 hp electric motor
S-501	1	Sour Water Storage - stainless steel horizontal tank designed for 15 psig at 180°F 12'-0" diameter 10" - 0 high

PROCESS CONDENSATE TREATMENT SECTION (Cont'd)

Item No	Quantity	Description
T-501	1	Ammonia Stripper - carbon steel tower designed for 30 psig at 300°F. 3'-0' diameter x 30' - 0" high and packed with 2 inch ceramic intalox saddles.
X-501	1	Waste Water Treatment System - Powder Activated Carbon Treatment (PACT) package including: C-501 Air blower H-501 Virgin carbon storage H-502 Polyelectrolyte storage P-503 Virgin carbon feed pump P-504 Polyelectrolyte feed pump S-502 Settling tank S-503 Aeration contact tank

FUEL CELL SECTION

Item No	Quantity	Description
C-601	1	Two stage air compressor with inter-cooler. Gear driven by turboexpander, complete with controlling instrumentation and lubrication system. Inlet discharge pressure 14.7/70 psia, 14,000 scfm; 2200 HP.
C-602	1	Air circulator, single stage, Inlet/ Discharge pressure 70/71 psia, 286,200 scfm; 500 HP.
CC-601	1	Catalytic Combustor. Pressure vessel containing Pt/Pd catalyst on metalor ceramic matrix, complete with mixing manifold.
E-602	1	Intercooler heat exchanger for air compressor. 2.1×10^6 Btu/Hr duty with 200 gpm cooling water flow.
EG-601	1	Electric Generator, gear driven by turboexpander, 2.78 MW.
F-601	1	Air Filter for air compressor intake.

EQUIPMENT LIST (Cont'd)

FUEL CELL SECTION (Cont'd)

Item No	Quantity	Description
FC-601	20	Fuel Cell Stack assembly, 375 kw each, 4'6" dia x 11'6" carbon steel pressure vessel containing 4 stacks of phosphoric acid cells with pt catalyst electrodes. Complete with insulation, instrumentation and electrical junction box. Mounted on elevated platform with manifold piping below.
GA-601	1	Station and Instrument Air. 200 SCFM compressor, with 100 ft^3 air reservoir. Delivery pressure 125 psig.
GH-601	1	Hydrogen gas supply system 200 lb of hydrogen stored in pressure cylinders with flow and pressure control. Delivery pressure 375 psig.
GN-601	1	Nitrogen gas supply system. Consisting of 7' diameter by 15' high liquid nitrogen storage tank, complete with vaporizing liquid/air heat exchanger and pressure/flow control. Delivery pressure 375 psig.
T-601	1	Turboexpander, pressure range 64 to 17 psia with 101,000 lb/hr flow; 3,929 HP

POWER CONDITIONING SECTION

Item No	Quantity	Description
PC-601	1	7.5 MW power conditioning converted system including current consolidator dc/dc converter, dc/ac converter.
PC-603	1	Electrical Protection Unit
PC-602	1	Output transformer 3-winding, liquid-filled 11 MVA, 3Ø.
PC-604	1	15 kV class metal-clad breaker
PC-605	1	Auxiliary power transformer 2500 kVA, 13800/480V.

POWER CONDITIONING SECTION (Cont'd)

Item No	Quantity	Description
PC-606	1 Lot	Miscellaneous transformers 480/208/120V
PC-607	1 Lot	Power Panels
PC-608	1	480 V Motor Control Center

THERMAL MANAGEMENT SECTION

Item No	Quantity	Description
B-601	1	Heat Recovery Steam Generator with auxiliary burner: Inlet gas 100,977 lb/hr, 737°F, auxiliary burner fuel 878 lb/hr oils/tars, 15,7 x 10^6 Btu/hr; heated gas 1133°F; boiler steam output 27,383 lb/hr, 130 psia, 347°F; feedwater heater water 28,752 lb/hr, 281°F inlet, 347°F outlet; economizer water 165°F inlet, 217°F outlet; 5% boiler blowdown; combination air 12,814 lb/hr at 60°F; estimated surface areas 6,000 ft^2 boiler section, 5,200 ft^2 FW heater section, 2,400 ft^2 economizer section, design pressure/temperature gas side 10 psig/1300°F, steam side 150 psig/400°F; 25°F pinch point; 98% efficiency
B-602	1	Fuel Cell Air Heat Recovery Steam Generator: inlet gas - 1,235,645 lb/hr, 365F; exit gas - 290F; boiler steam 18,957 lb/hr, 50 psia, 281°F; feedwater heater water 50,426 lb/hr, 242°F inlet, 231°F outlet; gas cooler water 49,149 lb/hr, 100°F inlet, 157°F outlet; 5% boiler blowdown; surface areas (est.) - boiler 20,000 ft^2, feedwater heater 3,300 ft^2, gas cooler 1,100 ft^2; design pressure/temperature - gas side 75 psig/400F, water side FW heater and gas cooler 150 psig/400F, steam/water side boiler 50 psig/300F; 98% efficiency; air avg. specific heat .245 Btu/lb-F; 25F pinch point temperature.

EQUIPMENT LIST (Cont'd)

THERMAL MANAGEMENT SECTION (Cont'd)

Item No	Quantity	Description
C-602	2 (1 Spare)	HRSG Burner Air Fan: Centrifugal forced draft; test block flow 3,300 cfm, static pressure 80 in. WG; 75 hp motor
D-601	1	Deaerating Heater; inlet water 49,149 217F; operating pressure/temperature 26 psia/242F; deaerating steam 1,277 lb/hr, 1191.7 Btu/lb; 10 minute storage capacity (1,100 gal).
E-601	1	Blowdown Heat Exchanger: shell side inlet water - 1,369 lb/h, 347F; tube side inlet water 49,149 lb/hr, 159 F; 10F drain approach temperature; copper nickel tube area 25 ft^2 (est.)
E-603	1	Steam Condenser: rated steam flow 20,000 lb/hr, duty $20x10^6$ Btu/hr, 4 in Hga; two-pass; 90/10 CuNi tubes 2,200 ft^2 (est.) 18 ft long, 3/4 in. dia. 18 Bwg, 90% cleanliness factor, cooling glycol water 2,100 gpm, 50F inlet, 25F rise; 5 min. hotwell storage (200 gal); 6.5 ft/s velocity
E-604	1	Blowdown Heat Exchanger: shell side inlet water 947 lb/hr, 138F; tube side inlet water 49,149 lb/hr, 157F; 10F drain approach temperature; copper nickel tube area 18 ft^2 (est)
E-605	1	Air Cooler with Demister: Inlet gas 114,669 lb/hr, 307F; exit gas 100F; gas specific heat 0.266; inlet air 1,410,000 lb/hr, 26F; outlet air 36F; heat duty 3,380,000 Btu/hr; copper nickel bare tube surface area 2,984 ft^2; 16 ft wide x 32 ft long tubes x 5 tube rows deep; 2 reversible fans, each 25 hp; condensed vapor flow 8,914 lb/hr
J-601	1	Steam Jet Air Ejector: Two-stage, with condenser, 120 psia steam

EQUIPMENT LIST (Cont'd)

THERMAL MANAGEMENT SECTION (Cont'd)

Item No	Quantity	Description
J-602	1	Steam Jet Pump: 120 psia/40 psia steam
P-601A, B	2 (1 spare)	Feedwater Pump: 120 gpm, 490 ft TDH, 30 hp motor, bronze fitted
P-602A, B	2 (1 spare)	Condensate Pump: 45 gpm, 105 ft TDH, 5 hp motor, bronze fitted
P-603A, B	2 (1 spare)	Makeup Water Pump: 110 gpm, 185 TDH, 15 hp motor, bronze fitted
S-601	1	Condensate Storage Tank: 20,000 gal. water storage, 12' dia. x 24'high, lined carbon steel with rubber bladder
T-602	1	Steam Turbine: Condensing multi-stage type, inlet pressure range 40-120 psia, 2.5 in. Hga in exhaust pressure 700 bhp with 20,000 lb/hr, 40 psia, rated steam flow
J-601	1	Vent Stack: Carbon Steel 36 in dia 80 ft/s gas velocity.

COOLING WATER SECTION

Item No	Quantity	Description
E606	1	Glycol/Air Cooler, 3800 gpm, 110°F outlet glycol, 75°F entering air 20°F range.
E-607	1	Glycol/Water Gasifier Cooling Water Heat Exchanger, stainless steel, 2.51×10^6 Btu/hr duty, 400 ft^3 effective area
P-607 A, B	2 (1 spare)	Cooling Water Pump, centrifugal, horizontal, 3800 gpm, 120 ft head, driven by a 200 HP motor. Materials: Bronze impeller, CI casing, stainless steel shaft.
P-608 A, B	2 (1 spare)	Gasifier Cooling Water Pumps, centrifugal, horizontal 80 gpm, 60 ft head, driven by a 3 HP motor. Materials: Bronze impeller, CI casing, stainless steel shaft
S-603	1	Gasifier Overflow Tank, carbon steel, 3 ft diameter, 4 ft high.

EQUIPMENT LIST (Cont'd)

WATER TREATMENT SYSTEM

Item No	Quantity	Description
D-602 A, B	2	Sodium Softener: 3' diameter 6' straight side with dished heads. Vessel - rubberlined carbon steel, PVC piping and internals 5' bed exchange depth - Cocurrent regeneration
G-602 A, B	2	Cartridge Filter - 10 micron cartridge filters, duplex arrangement PVC lined ductile iron housing. Quick disconnect cover for cartridge replacement. Inlet and outlet 2 inch flanged connections, 150 lb design
P-605 A, B	2 (1 spare)	Degasifier Transfer Pump - horizontal centrifugal type pump. Rated at 30 gpm and 100 ft TDH. 3 HP motor at 3600 rpm FRP casing and impeller
P-606 A, B	2 (1 spare)	Condensate Transfer Pump - horizontal centrifugal type pump. Rated at 25 gpm and 100 ft TDH. 3 HP motor at 1800 rpm
P-611 A, B	2 (1 spare)	Vacuum Pump Liquid Ring Vacuum Pump. 975 RPM pump speed with belt drive and 10 HP motor. Cast iron casing.
T-603	1	Vacuum Degasifier: 2'-0" diameter 5'-0" straight side with 200 gal clearwell. Vessel - coated carbon steel with PVC internals. Packing: Maspac FN-200 40 cu ft.

AD-A173 688 FEASIBILITY STUDY OF COAL GASIFICATION/FUEL CELL/COGENERATION PROJECT FOR..(U) EBASCO SERVICES INC NEW YORK B ROSSI ET AL. NOV 85 DAAG29-85-C-0007 3/3

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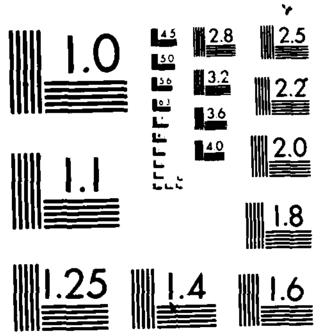

MICROCOPY RESOLUTION TEST CHART
NATIONAL BUREAU OF STANDARDS-1963-A

APPENDIX B

Alternate UTC Fuel Cell System

ALTERNATE UTC FUEL CELL SYSTEM

If a UTC fuel cell is substituted for the base case, the GFC system efficiency rises to 38.9% and the heat rate reduces to 12,600 Btu/kwh. The HRSG is located downstream of the gas expander and the tars and oils are fired in an HRSG supplementary burner located upstream of the HRSG.

Of the Main Post maximum monthly average steam requirement (this is not the peak load) in February of 39,300 lb/hr steam, 26,700 lb/hr can be satisfied by steam available from the GFC. This is after deducting 35,700 lb/hr for gas processing and for space heating of the GFC enclosure from the gross TMS system output of 62,400 lb/hr.

AT a peak heating load of 55000 lb/hr, the greater thermal capacity of the UTC unit reduces the required capacity of incremental gasifiers to supply raw gas to the reworked existing boilers from approximately 41000 lb/hr for the Westinghouse Unit to 31000 lb/hr. System performance is summarized in Table B-1 and the overall energy balance given in Table B-2. A flow diagram is provided in Figure B-1.

TABLE B-1

SYSTEM PERFORMANCE

UTC SYSTEM ALTERNATE

a	Coal Delivered to Plant, Tons/D	277.4
b	Excess Coal Fines (1), Tons/D	32.6
c	Coal Input to Gasifier (2), Tons/D	244.8
d	Heating Value of Coal Input (3), Btu/hr	153.2×10^6
e	Fuel Cell Output, MW DC	11.6
f	Power Conditioner Output, MW AC	11.0
g	Power from GAs Expander, MW	2.6
h	Power from Steam Turbine, MW	.4
i	Auxiliary Power, MW	3.8
j	Net Power, MW	10.2
k	Export Steam 230 psia, lb/hr	23,600
l	Tar and Oils Heat Content, Btu/hr x 10^{-6}	21.9
m	Heat Rate, Btu/KWh (4)	12,600
n	Overall Plant Efficiency, % (4)	38.9

1. Coal fines in excess of 15%. It is assumed that these fines which are in excess of 15% will be trucked to Fort Wainright for use in their boilers. If Fort Wainright cannot accept these fines, they may be fired in future coal boilers at Fort Greely.

2. Based on gasifier accepting 15% fines and coal received with 25% fines.

3. Based on higher heating value of 7,510 Btu/lb.

4. Definitions:

   Heat Rate = ((d) - (k)H) (1000 j)
   Overall Plant Efficiency = $(3.412 \times 10^6$ (j) + (k)H)/(d)
   where H = export steam/condensate enthalpy difference

TABLE B-2

OVERALL ENERGY BALANCE (JTC ALTERNATE)

Item		Energy (10^6 Btu/hr) In	Out
Energy in Coal Delivered to Plant		173.6	
Energy Produced (Gross)			47.77
Fuel Cells	37.54		
Gas Expander Generator	8.87		
Steam Turbine Generator	1.36		
Parasitic Power			(13.00)
Export Steam			24.80
Energy in Byproducts			22.40
Coal Fines	20.4		
Cyclone Carbon Dust	1.30		
Ash	.70		
Heat Rejected by Cooling Tower			35.00
Other Heat Releases to Environment			56.63
CO Shift Air Cooler	13.4		
HRSG Stack Loss	25.1		
Miscellaneous	18.13		
TOTAL		173.6	173.6

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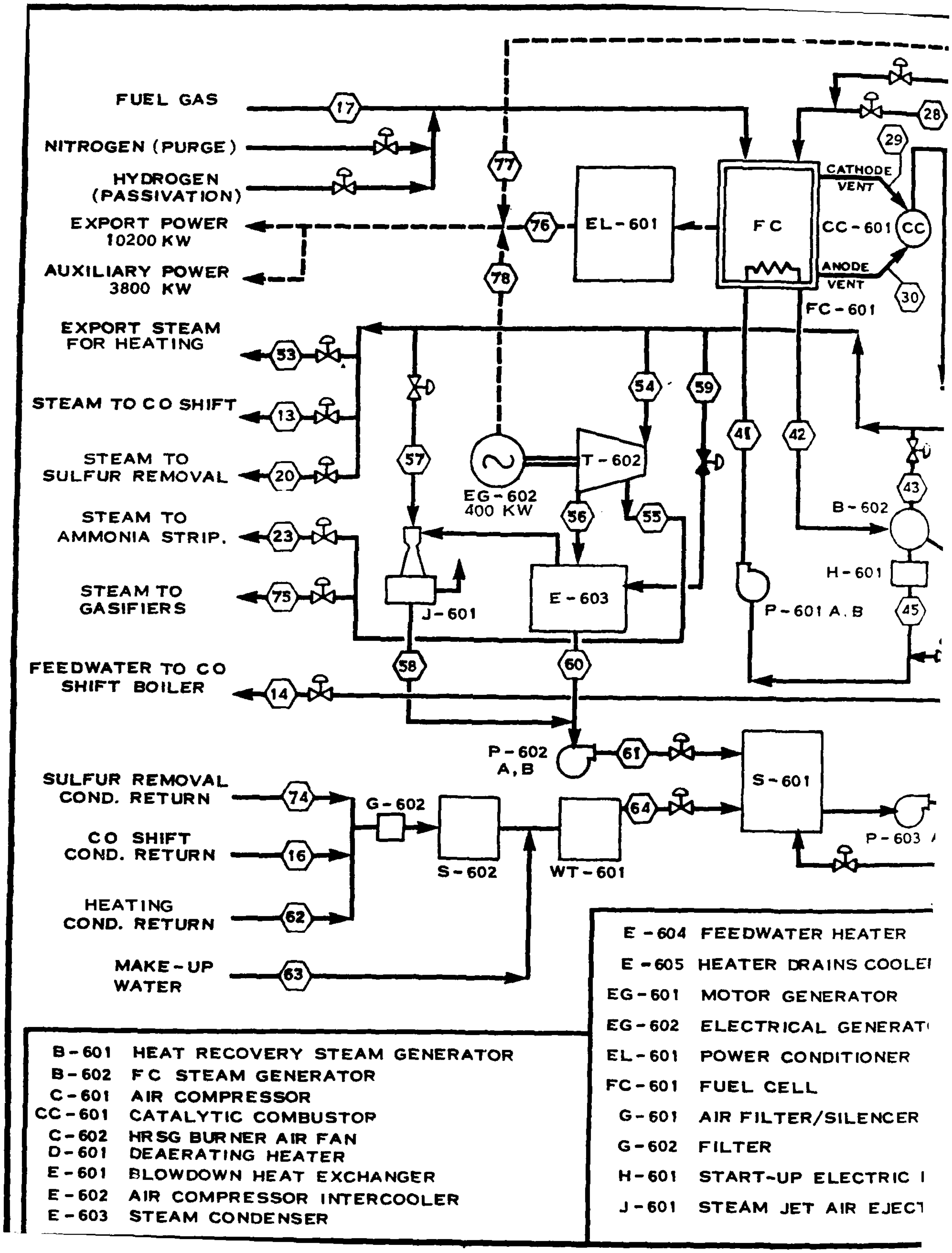
FUEL GAS
NITROGEN (PURGE)
HYDROGEN (PASSIVATION)
EXPORT POWER 10200 KW
AUXILIARY POWER 3800 KW
EXPORT STEAM FOR HEATING
STEAM TO CO SHIFT
STEAM TO SULFUR REMOVAL
STEAM TO AMMONIA STRIP.
STEAM TO GASIFIERS
FEEDWATER TO CO SHIFT BOILER
SULFUR REMOVAL COND. RETURN
CO SHIFT COND. RETURN
HEATING COND. RETURN
MAKE-UP WATER
EL-601
FC
FC-601
CATHODE VENT
ANODE VENT
CC-601
CC
EG-602 400 KW
T-602
J-601
E-603
B-602
H-601
P-601 A, B
P-602 A, B
S-601
G-602
S-602
WT-601
P-603
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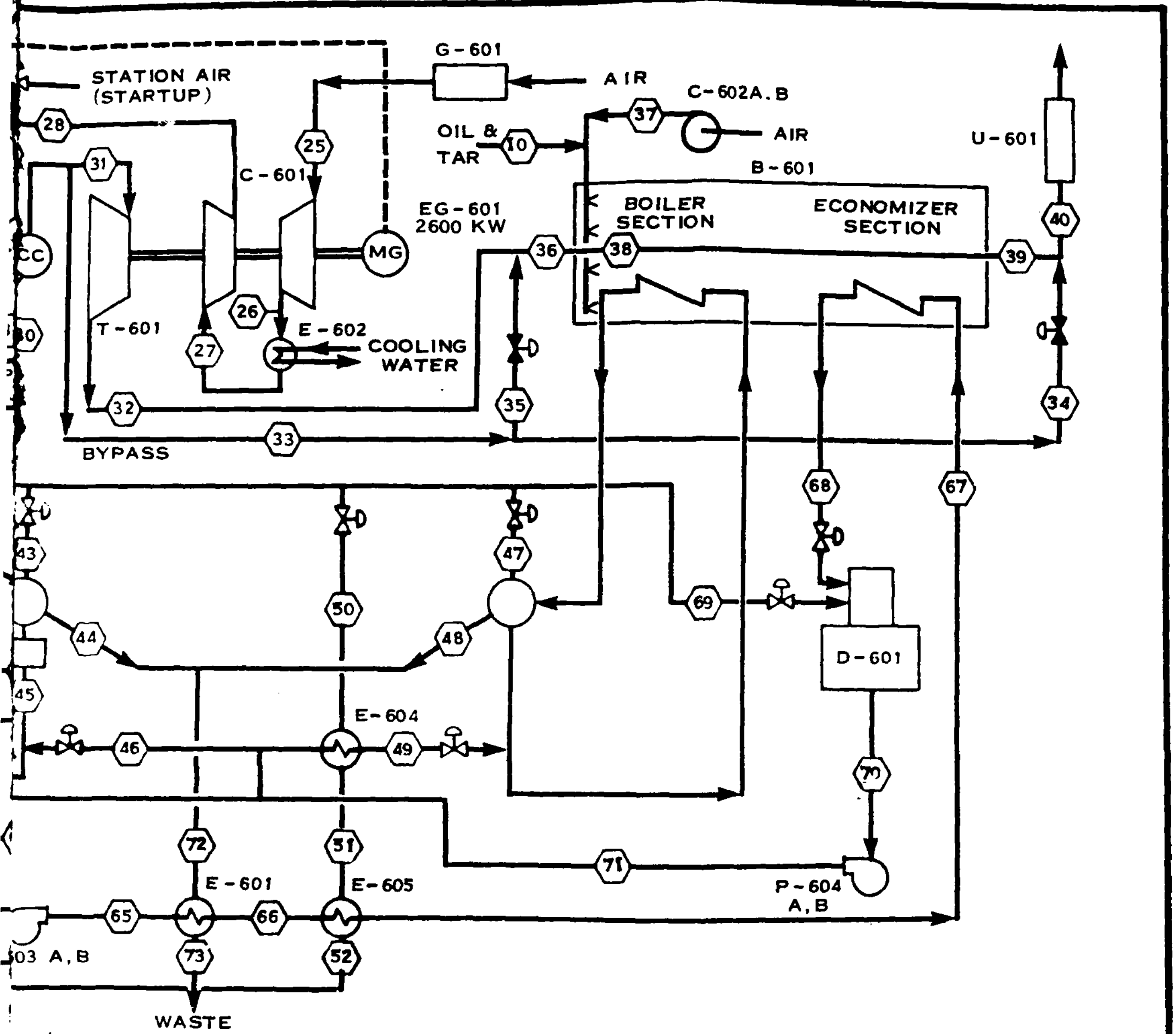
E-604 FEEDWATER HEATER
E-605 HEATER DRAINS COOLE
EG-601 MOTOR GENERATOR
EG-602 ELECTRICAL GENERAT
EL-601 POWER CONDITIONER
FC-601 FUEL CELL
G-601 AIR FILTER/SILENCER
G-602 FILTER
H-601 START-UP ELECTRIC
J-601 STEAM JET AIR EJEC
B-601 HEAT RECOVERY STEAM GENERATOR
B-602 FC STEAM GENERATOR
C-601 AIR COMPRESSOR
CC-601 CATALYTIC COMBUSTOR
C-602 HRSG BURNER AIR FAN
D-601 DEAERATING HEATER
E-601 BLOWDOWN HEAT EXCHANGER
E-602 AIR COMPRESSOR INTERCOOLER
E-603 STEAM CONDENSER



R	P-601	CIRCULATING PUMP
LER	P-602	CONDENSATE PUMP
	P-603	MAKE-UP WATER PUMP
ATOR	P-604	FEEDWATER PUMP
R	S-601	CONDENSATE STORAGE TANK
	S-602	CONDENSATE PROVER TANK
ER	T-601	GAS EXPANDER
	T-602	STEAM TURBINE
C HEATER	U-601	VENT STACK
CTOR	WT-601	MAKE-UP DEMINERALIZER

DOA / GEORGETOWN UNIVERSITY

COAL GAS / FUEL CELL / COGENERATION

FORT GREELY ALASKA SITE, ALTERNATE
PROCESS FLOW DIAGRAM
UTC FUEL CELL AND
THERMAL MANAGEMENT SYSTEMS

FIGURE B-1

EBASCO SERVICES INCORPORATED

APPENDIX C

MASS BALANCE BASES

APPENDIX C

MASS BALANCE BASES

Mass Balances are based on established engineering procedures and on sources for data and criteria as follows:

Coal Gasification (Table 6.2-5)

Basic Data	Source
Coal Composition	U.S. Geological Survey
Raw Gas Composition	Dravo Engineering Co.
Tax & Water Yield	Dravo Engineering Co.
Steam And Oil Gasifier	Dravo Engineering Co.
Ash and Cuclone Dust Prouduction	Dravo Engineering Co.; Black Sivalls & Bryson (BS&B)

Ash and cyclone dust production was determined using information provided by Wellman-Galusha gasifier vendors and by EPRI report, EM 3162.

Total coal consumption is based on fuel cell manufacturer criteria for minimum concentration of H_2 and maximum concentration of CO (see paragraph 6.4).

Gas Cooling, Cleaning and Compression (Table 6.3-2)

The mass balance for this section was based on the spray water added to the incoming hot raw gas for cooling by adiabatic saturation, the subsequent removal of water during compression, the distribution of oils/tars between the vapor and liquid phases (based on information in EPRi report, EM 3162) and on condensate blowdown.

Thermodynamic data was taken from "Chemical Process Principles" by Hougen and Watson and "Chemical Engineering Handbook" by Perry, Chilton and Kirkpatrick.

The compressor was designed for the pressure required by its fuel cell with allowance for process equipment pressure drops.

CO Shift (Table 6.3-3)

The mass balance used thermodynamic data proided by the catalyst manufacturer and "Chemical Process Principles" by Hougen and Watson. Inlet temperatures are those accepted by the industry for end of run conditions. The approach to equilibrium temperature for CO and COS conversion and the ratio of steam to dry gas were established to meet the desired CO concentration.

Sulfur Removal and Recovery (Table 6.3-4)

The fuel manufacturer's anode feed gas specification, (Table 6.4-1) for maximum sulfur concentration is the primary criteria for design of the sulfur removal system. The mass balance was made with reference to information in EPRI report EM 3334 and provided by licensor, R M Parsons, for the Stretford unit.

Equilibrium conditions for the COS hydrolysis were based on in-house data developed during previous projects and on the catalyst manufacturer's infomation. The heat and material balance for the final polishing unit is based on EPRI report EM 3334.

Process Condensate Treatment (Table 6.3-5)

The mass balance for this section referred to information from the PACT system licensor (ZIMPRO) and EPRI report, EM 3162 for the ammonia stripping. The effluent composition is based on "EPA Quality Criteria For Water-1976".

Fuel Cell System (Table 6.4-3)	Source
Basic Data	
Anode Feed Gas	Westinghouse Electric Corp
Compressed Air Flow And Pressure	Westinghouse Electric Corp
Mass Flow and Composition of Anode and Cathode Exhaust	Note 1
Catalytic Combustor Exhaust Compositon and Temperature	Note 2

Notes:

1. Flow rate and composition of anode and cathods vent gases are based on hydrogen and oxygen utilization efficiencies given by Westinghouse and on composition of anode feed gas and compressed air, respectively.

2. Catalytic combustor exiting temperature are based on complete combustion of vent gases from the fuel cell.

Thermal Management Sytem (Table 6.5-2)

Basic Data	Source
Gas Mass Flow Rate to HRSG	Table 6.4-2
Gas Temperature to HRSG	Table 6.4-2
Steam Turbine Efficiency	Elliott Co.
HRSG Pinch Point Temooerature	Industry Practice
Economizer Approach Temperature	Industry Practice
Fuel Cell Heat Rejection	UTC

Based on pinch point temperature (difference between temperature of gas and saturated steam where gas exists boiler), steam saturation temperature, feed water temperature and the temperature of gas entiring the HRSG, steam flow from the HRSG and gas temperature drop up to the economizer section is determined.

After steam flow from the fuel cell air cooling system HRSG is combined with steam flow from the turbine exhaust gas HRSG, process steam flows including steam for feedwater heating are deducted to give the total net steam flow available for export and for generation of shaft power in EG-601.

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